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Mining Assisted Methods for Recovering Petroleum, Heavy Oil and Oil Sands

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MINING ASSISTED METHODS FOR RECOVERING PETROLEUM, HEAVY OIL, AND OIL SANDS

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The basic idea of tunneling to reach underground petroleum deposits has been around since antiquity. The development of modern well drilling technology made the mining approach obsolete as long as virgin petroleum reservoirs could be found easily. Typical oil well production technology, however, will recover perhaps only one-third of the original oil in place. With conventional exploration being forced into more expensive frontier areas, the two-thirds of the oil left behind becomes an attractive target for other technologies. Enhanced oil recovery methods based on injection of miscible gases, steam, solvents, surface active agents, polymers, etc., may recover only 10 to 15 percent of the oil remaining.

Mining assisted methods can recover up to 90 percent of the total oil in the target zone, and are receiving renewed interest for applications to light oil, heavy oil, and oil sands.

EARLY UNITED STATES EFFORTS

Early efforts using mining assisted methods for petroleum were summarized in United States Bureau of Mines Bulletin 351 in 1932.[1] Energy Development Consultants updated Bulletin 351 for the Bureau of Mines in 1978.[2]

Although a number of small-scale attempts to use mining assisted methods were made in United States, no projects appear to have been economically successful, because they were never extended beyond the initial trial. Some of the efforts summarized in references (1) and (2) include:

- In 1866 Union Oil drove 31 oil drainage tunnels, up to 1,900 feet long, in Ventura County, California.
- At Newport Beach, California in the 1920s an inclined shaft was sunk 500 feet to an oil sand, and a drift developed at the bottom of the shaft.
- Two oil mines were developed in southwest Colorado in the early 1900s. Production is known to have been as high as 50 barrels per day.
- Near Tidiaute, Pennsylvania in 1864 an 8 x 12 foot shaft was sunk to oil sands at 165 feet and several holes drilled from the bottom of the shaft.

- The Jacksboro field in Texas was the site for a 100 foot vertical shaft in 1920. A 100 foot tunnel was driven from the shaft and 9 wells drilled from within the tunnel.
- In Morgan County, Ohio in 1939 the Ohio Level Well Company sank a 30 foot diameter pit and drilled horizontal holes from the bottom. A similar effort by another company occurred in 1945.
- The Venango Development Company working in Pennsylvania's Franklin oil field in the 1940s sank a 10 foot vertical shaft 370 feet, with a 27 foot diameter work chamber at the bottom. Two horizontal holes over 2,000 feet long were drilled from the chamber.
- In 1943 at LaCygne, Kansas a 230 foot shaft was sunk with two 16 foot work stations at the bottom. Fourteen horizontal holes with 7,000 feet total length were drilled.

EARLY OVERSEAS EFFORTS

Mining assisted petroleum production has been attempted on a much more extensive scale at several overseas locations. At Pechelbronn, France, more or less continuous development was carried out from the 1800s through 1953, with a cumulative production of around 20 million barrels. Drainage galleries or tunnels off a vertical shaft were at first driven into the sand itself but later above the oil sand, and collection pits sunk from the floor of the galleries. Boreholes up to 300 feet long were also drilled from the galleries at various angles. Natural drainage was sometimes augmented with compressed air. In 1928 there were 800 underground employees, and new galleries were driven in excess of 10,000 feet per year for several years.

The Wietze field near Hanover, Germany was developed by mining assistance around 1920 and was producing until about 1963. Vertical shafts over 800 feet deep reached the pay zone and horizontal drifts or passageways were developed in the oil zone itself. The drifts outlined blocks about 100 by 200 feet. Drain holes were drilled at an upward inclination from the drifts, some of them penetrating higher sand intervals. Oil ran down drainage troughs along the passageways. Over 400 men were working at the mine in 1929.

The Higashiyama mine in Japan used similar techniques in the 1940s. Inclined shafts were sunk to the oil zone, then drifts and crosscuts developed so as to divide the mine into blocks 130 feet to 330 feet by 50 feet to 330 feet. Upward-inclined drain holes up to 160 feet long were then drilled from the passageways. Approximately 200 men produced 37,000 barrels in 1945.

MORE RECENT EFFORTS

Russia

The most extensive effort of the current era is the Yarega field in Russia. The mine is developed on two different levels—one above the pay zone and one at the bottom of the reservoir. In the lower workings, 80 feet diameter, doughnut-shaped work chambers are developed on 4.5 acre spacing. From each chamber about 250 production holes, 650 to 800 feet long, are drilled in a radial pattern. Steam injection wells are drilled downward from the upper mine level.

The steam method has been in use at Yarega since 1968. At the World Petroleum Congress in September 1983, the Soviets claimed production costs of $12 to $16 per barrel, and discussed plans to increase production to 10.6 million barrels per year.

Romania

In Romania, the Sarata-Monteoru deposit has been producing since 1925. The techniques used are said to be the same as those used at Pechelbronn. Expansion to other fields is planned.

Wyoming

Conoco developed a gravity drainage project in Johnson County in 1977. Access was provided by an inclined shaft from an adit. Horizontal drain holes 2,000 feet long were drilled from a work chamber at the bottom of the access shaft. Initial yield was about 100 barrels per day. A second production set was developed in 1982 from a vertical shaft, using the same radial-holes-from-work-chamber approach.

California

Cornell Heavy Oil Process (HOPCO) is developing a heavy oil project in the Kern River field of California. The HOPCO "hot plate" process involves sinking a vertical shaft below the pay zone, constructing a work chamber at the bottom, and drilling horizontal radial holes for both oil production and steam injection. Funding is expected from the United States Synthetic Fuels Corporation. A total recovery of 65 percent of the oil in place is expected.

TECHNOLOGY SUMMARY

The use of mining assisted methods for oil recovery is an attempt to increase well-bore exposure within an oil-producing zone at less cost than the cost of drilling additional wells from the surface. The economic tradeoff is relatively simple in principle. If a pay zone is 100 feet thick and lies 1,000 feet deep, then 1,100 feet of drilling of vertical wells is required for each additional 100 feet of pay zone exposure. If a mine shaft or tunnel is sunk to the pay zone, then development drilling from the mine can achieve 100 percent pay zone exposure for every foot drilled. The saving of up to 90 percent in drilling footage can be balanced against the cost of the mine development and the difficulty of drilling from underground workings. Using this simple tradeoff, mining assisted methods cannot compete with primary production of typical light oil reservoirs by conventional means. Conventional production "skims off the cream" of an oil body by taking advantage of the natural energies stored in a reservoir. This natural energy may be in the form of gas cap pressure, solution gas pressure, reservoir water drive, formation pressure, etc. When these sources of reservoir energy are missing or exhausted, and production depends solely on gravity flow to a well bore, then oil moves through the reservoir only slowly. Increased drilling becomes necessary to capture significant quantities of oil in a reasonable time period. As the required well spacing decreases, well drilling costs approach the region of equivalence to mining-assisted drilling.

ECONOMIC SUMMARY

Economic assessments have been made by Energy Development Consultants in Reference (2), in a companion study by Golder Associates (Reference 3), in a 1982 Department of Energy study by Commercialization Insights (Reference 4), and in a 1983 study by Stone and Webster (Reference 5). Each of the studies used different assumptions on reservoir properties, drilling patterns, and development costs. The common themes were that economics are highly reservoir specific, that mining assisted methods will be practical only with richer-than-average reservoirs (barrels per acre), and that steam-assisted mining assisted methods in heavy oil reservoirs are an attractive possibility. Steam is a major cost in steam-assisted applications. The high well-bore exposure per acre achievable with mining assisted methods should increase steam sweep efficiencies and thereby lower operating costs.

Gravity Drainage

Energy Development Consultants (EDC), Golder Associates (GA), and Stone & Webster (SW) each analyzed a mining assisted case for gravity drainage alone. The results were quite different. EDC showed highly favorable results, in the range of 30 to 50 percent DCFROR. GA calculated a less than 10 percent rate of return, and the SW case did not even recover the original capital investment. We have attempted to normalize the three cases to see if any consistent conclusions can be reached.

The most obvious possibility for discrepancy is in the assumptions for reservoir parameters and recovery efficiency. As seen in Table 1, the biggest difference in reservoir parameters is in the viscosity. SW, by design, chose a heavy oil reservoir suitable only for steam-assistance. We therefore normalized this parameter by assuming the same percent recovery for all three cases. Theory is not available to predict accurately the ultimate recovery as a function of inclined drainhole patterns and spacing. A recovery of 50 percent of the starting oil in place was applied to each case.

All three cases used the same basic technique of mining and drilling, shown in Figures 1 through 3. Vertical shafts are sunk to a stratum below the oil reservoir. Horizontal tunnels and drifts are then developed in a block pattern. Upward-inclined drain holes are drilled in a fan pattern from drill stations or rooms which are developed in or beside the tunnels and drifts. The biggest difference is in the drain hole spacing, where EDC assumed 220 feet center-to-center, GA assumed 50 feet, and SW assumed 100 feet. There is no good way of calculating an optimum pattern.

Because of the different years in which the estimates were prepared, differences in cost factors are to be expected, but it appears that the three estimates for the cost of mining out the tunnels and crosscuts are widely different. Other cost factors do not seem to be enough different to have a large effect.

Both EDC and SW structured the economic model like an oil field project. All construction is completed in two years, and then production occurs until depletion. GA, on the other hand, modeled it as a mining project. Mine development and production occur continuously and simultaneously over the life of the project. These two approaches create very different results when running a discounted cash flow evaluation because of the differing time periods involved. In order to equalize this factor, we simply computed total expenses over the life of each project and divided by the total barrels produced.

As seen in Table 1, the results range from $3 to $10 per barrel, exclusive of all taxes, royalties, severance, and cost of money. Considering the less dense well spacing, lower tunneling cost, and earlier basis year used in the EDC estimate, the spread is not unreasonable.

All three of the studies failed to make any comparison of cost for the mining assisted approach to that of drilling an equivalent number of conventional wells from the surface. This should be a key measure of the value of the mining assisted approach. We therafore took the drilling costs, reservoir depths, and drainage well spacng used in each study and calculated an equivalent cost for drilling the same number of conventional wells. Results appear in Table 2. In every case, using the internal cost parameters used in the original studies, the cost of drilling an equivalent number of conventional wells is less than the proposed mining assisted systems. This creates a strong argument against undertaking the risks of a mining assisted oil drainage project of the type studied unless some conclusive benefits (such as higher recovery efficiency with the same well spacing) can be demonstrated.

Steam-Assisted Drainage

Both GA and SW included a study of mining assisted steam injection to exploit a heavy oil reservoir. In Reference 4 Commercialization Insights (CI) updated the GA estimate and compared it to an estimate for the HOPCO process. For its steam-assist design GA placed the working level of the mine above the reservoir, and both steam injection and production holes are then drilled down into the oil zone. SW maintained the under-mined drainage system, but proposed steam injection from surface wells in one version. Schematics for the three cases are shown in Figures 4 through 6. Reservoir parameters are listed in Table 3.

The economic results listed in Table 3 show vastly different rates of return on investment. The SW case appears the least attractive, with a DCFROI of only 10 percent at a product price of $37.15. The high operating costs for the GA case are due to use of in-mine electrical boilers to produce steam, and to the slow rate of mine development. These are basic facets of the design, and we therefore conclude that the design is relatively unattractive.

In comparing the SW and CI/HOPCO estimates, however, the capital investment per barrel is approximately the same. We note that SW used a steam ratio of 5 instead of 3, and used a recovery factor of 50 percent instead of 68 percent. Also, SW deducted one-eighth royalty and a windfall profits tax, while CI/HOPCO did neither. If these factors are made the same for both cases, there is no significant difference in the calculated rate of return on investment. There is probably no reason, based on design, to assume that any of these factors would be different if the two processes were developed in exactly the same reservoir conditions. The SW values for steam ratio and percent recovery are likely over-conservative, being based on conventional steam flooding performance without taking credit for any effects due to greatly increased well density. Overseas experience has shown that recoveries above 50 percent can be achieved.

Although the estimated technical and economic performance may be equal, the HOPCO design will be preferred over the SW design because of fewer risk factors. Both require the sinking of vertical shafts through the oil zone, but the SW design then requires extensive mine development in relatively close proximity to the reservoir zone. The HOPCO design also lends itself more readily to a modular development program, minimizing the total amount of capital which must be put at risk to prove the concept.

There are situations where the SW design may be suitable and the HOPCO not, as in the case of multiple pay zones separated by impermeable horizontal layers. Also, the HOPCO design uses steam only as a heating medium, not as a steam drive process. In all cases, we must again inquire whether additional conventional wells could be drilled to achieve the same result at lower cost. The CI report uses $57 per foot as a typical cost for drilling wells in steam flood projects. In both cases, we find that spending the same capital investment on conventional wells would result in something on the order of 3 wells per acre. Whether 3 wells per acre could achieve 50 percent recovery at a 3:1 steam/oil ratio is unknown.

CONCLUSIONS

As more experience is gained in their application, mining assisted techniques for oil recovery should find a market niche. At present that niche is undefined, but it will probably lie in shallow reservoirs, 200 to 2,000 feet in depth. Very shallow reservoirs at less than 200 feet can be developed from the surface with very high well densities at low cost, or else developed by extractive open-pit mining. At depths greater than 2,000 or 3,000 feet the costs and risks of mining in the reservoir zone are likely to remain prohibitive.

Where satisfactory recovery rates and percentages can be achieved by conventional wells on one or two acre spacing, there may be no advantage for the mining assisted approach. When closer well spacing is required, however, the mining assisted approach quickly shows a clearcut advantage (Figure 7). High density development can be justified only in reservoirs of greater than average richness.

The economic tradeoff between mining assisted and traditional approaches depends in some cases on whether it is easier to maintain heading in a horizontal hole drilled from underground or in a deviated drain hole drilled from the surface. As downhole measurement-while-drilling systems are improved, the advantage may rest with drilling from the surface.

Because the economic effects of drilling footage and recovery efficiency are magnified in a steam-assisted situation, the greatest potential for mining assisted methods is likely to be in this area. This suggests that heavy oil and oil sands will be the most favorable resource applications. There are various designs which show the same order-of-magnitude estimated economics, but the single vertical shaft with horizontal drain holes would appear to carry the least technical risk.

1. Rice, G. S., "Mining Petroleum by Underground Methods," United States Bureau of Mines Bulletin 351, 1932.

2. Hutchins, J. S., Bond, E., Bass, D., "Mining for Petroleum: Feasibility Study," contract JO275002, July 1978.

3. Edey, A., Kennedy, B., Readdy, L., "Oil Mining. A Technical and Economic Feasibility Study of Oil Production by Mining Methods," Bureau of Mines OFR 55-79, October 1978.

4. "An Evaluation of Alternatives for Production of Heavy Oil Using Mining, Drilling, and Steam Stimulation," DOE/SF/10888-T1, August 1982.

5. Piper, E. M., Riddell, A. W., Trent, R. H., "An Evaluation of Heavy Oil Mining (2 Volumes)," DOE/PC/30259-1, March 1983.

TABLE 1

COMPARISON OF MINING ASSISTED GRAVITY DRAIN ECONOMICS

	Energy Development Consultants	Golder Associates	Stone and Webster
Reservoir Assumptions			
Depth, Feet	3,000	1,200	900
Thickness, Feet	100	170	400
Net Pay, Feet	100	170	84
Permeability, Millidarcies	10	800	3,000
Porosity, Percent	20	32	35
Saturation, Percent	50		63
Viscosity, Cp	2	50	8,500
Acres	640	620	744
Oil in Place, Million Barrels	46	92	102
Cost Factors			
Year of Estimate	1977	1977	1982
Vertical Shafts, $/Foot	2,000		3,000
Tunnels, $/Foot	400	216	2,500
Drill Holes, $/Foot	35	20	32
Piping, $/Foot	13		
Drainhole Spacing, Feet, CC	220	50	100
Construction Time, Years	2	20	2
Costs (Thousand Dollars)			
Shafts	12,000		12,600
Mining Equipment			8,100
Tunnels	4,928		87,750
Drifts	14,872		
Piping	650		516
Pumping and Separation	2,400		4,900
Surface Equipment	700		6,188
Drill Holes	6,189	57,171	61,965
Contingency, Miscellaneous	22,550		
Total Initial Capital	65,000	21,989	185,019
Operating Cost, Dollars Per Year		22,795	3,420
Lifetime Operating Costs	5,000	455,900	68,400
Cost for 50% Recovery, $/Barrel	3.00	10.00	5.00

TABLE 2

COMPARISON OF MINING ASSISTED COSTS TO SURFACE DRILLING ALTERNATIVES

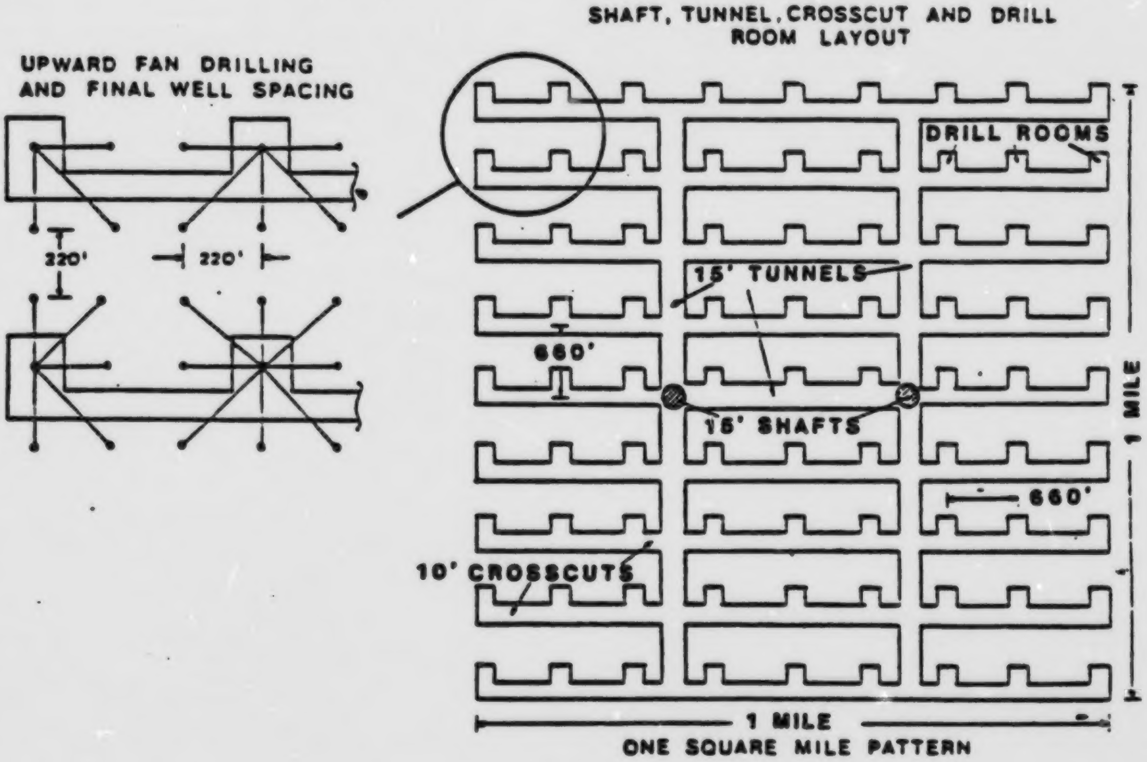
	Energy Development Consultants	Golder Associates	Stone and Webster
Mining Assisted Capital Costs, $MM	65	409	185
Equivalent Wells Per Acre	0.9	17.4	4.4
Equivalent Well Cost, $MM	60	259	94

TABLE 3

COMPARISON OF MINING ASSISTED STEAM INJECTION ECONOMICS

	Golder Associates	Stone and Webster	Commercialization Insights HOPCO
Reservoir Assumptions			
Depth, Feet	1,150	900	700
Net Thickness, Feet	20	84	60
Permeability, Darcies	1.8	3.0	2.5
Gravity, °API	14	14	14
Porosity	0.35	0.35	0.27
Barrels Per Acre-Foot	1,200	1,600	1,275
Acres	2,166	744	100
Cost Factors			
Steam/Oil Ratio	3.0	5.0	3.0
Well Density, Per Acre	17.4	4.4	1/3
Well Exposure, Feet Per Acre	644	600	208
Percent Recovery	50	50	68
Economic Results			
Capital Cost Per Barrel, Dollars	2.97	3.60	4.32
Project Life, Years	12	8	6
Operating Cost Per Barrel, Dollars	23.98	15.94	11.15
Selling Price, Dollars Per Barrel	30.00	37.15	30.00
DCFROI, Percent	7	10	34

ENERGY DEVELOPMENT CONSULTANTS
GRAVITY DRAINAGE LAYOUT



SHAFT, TUNNEL, CROSSCUT AND DRILL ROOM LAYOUT
UPWARD FAN DRILLING AND FINAL WELL SPACING
220'
220'
DRILL ROOMS
15' TUNNELS
660'
15' SHAFTS
660'
10' CROSSCUTS
1 MILE
1 MILE
ONE SQUARE MILE PATTERN

FIGURE 1

GOLDER ASSOCIATES GRAVITY DRAINAGE LAYOUT

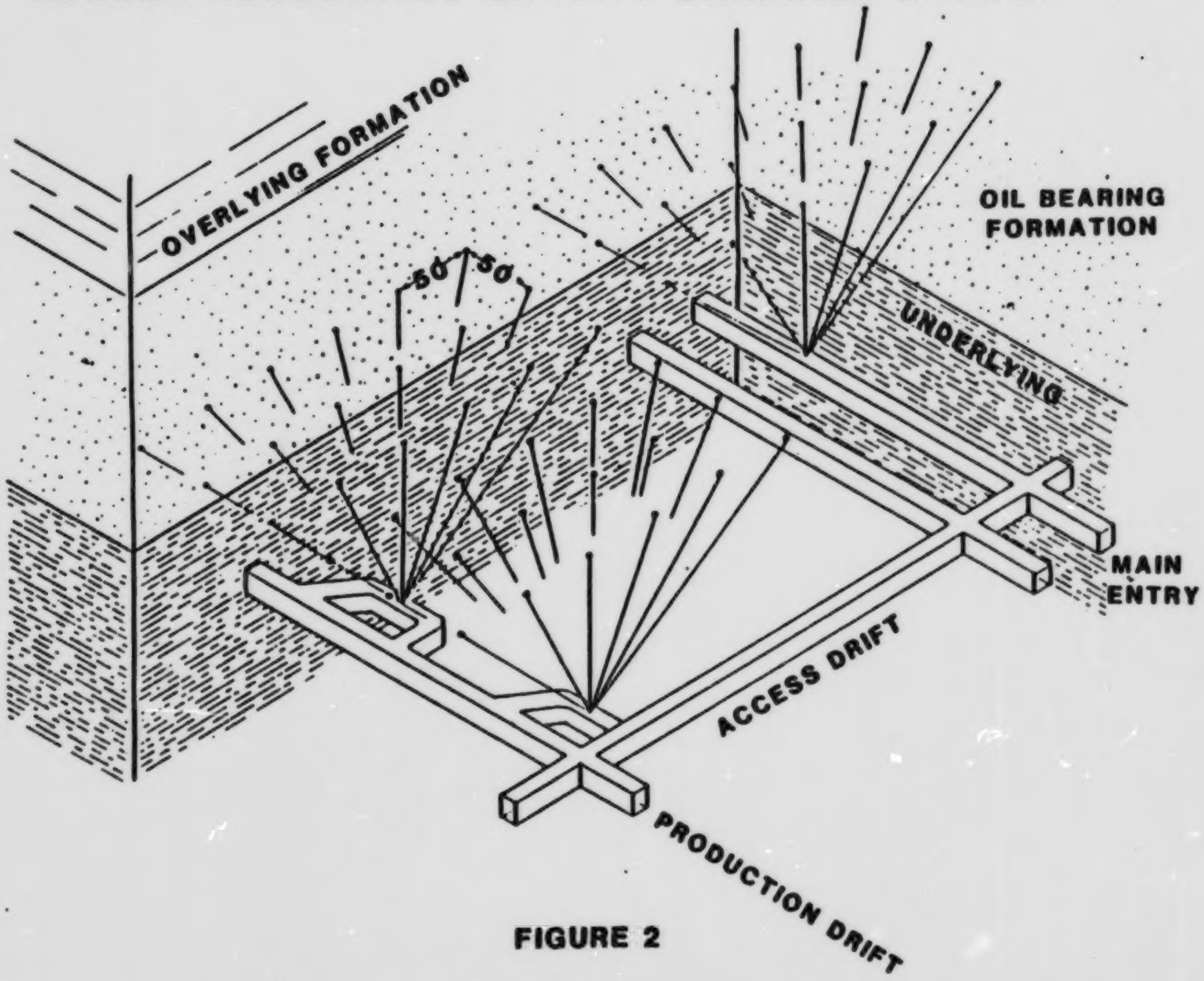

OVERLYING FORMATION
50'
50'
OIL BEARING FORMATION
UNDERLYING
MAIN ENTRY
ACCESS DRIFT
PRODUCTION DRIFT

FIGURE 2

STONE AND WEBSTER GRAVITY DRAINAGE LAYOUT

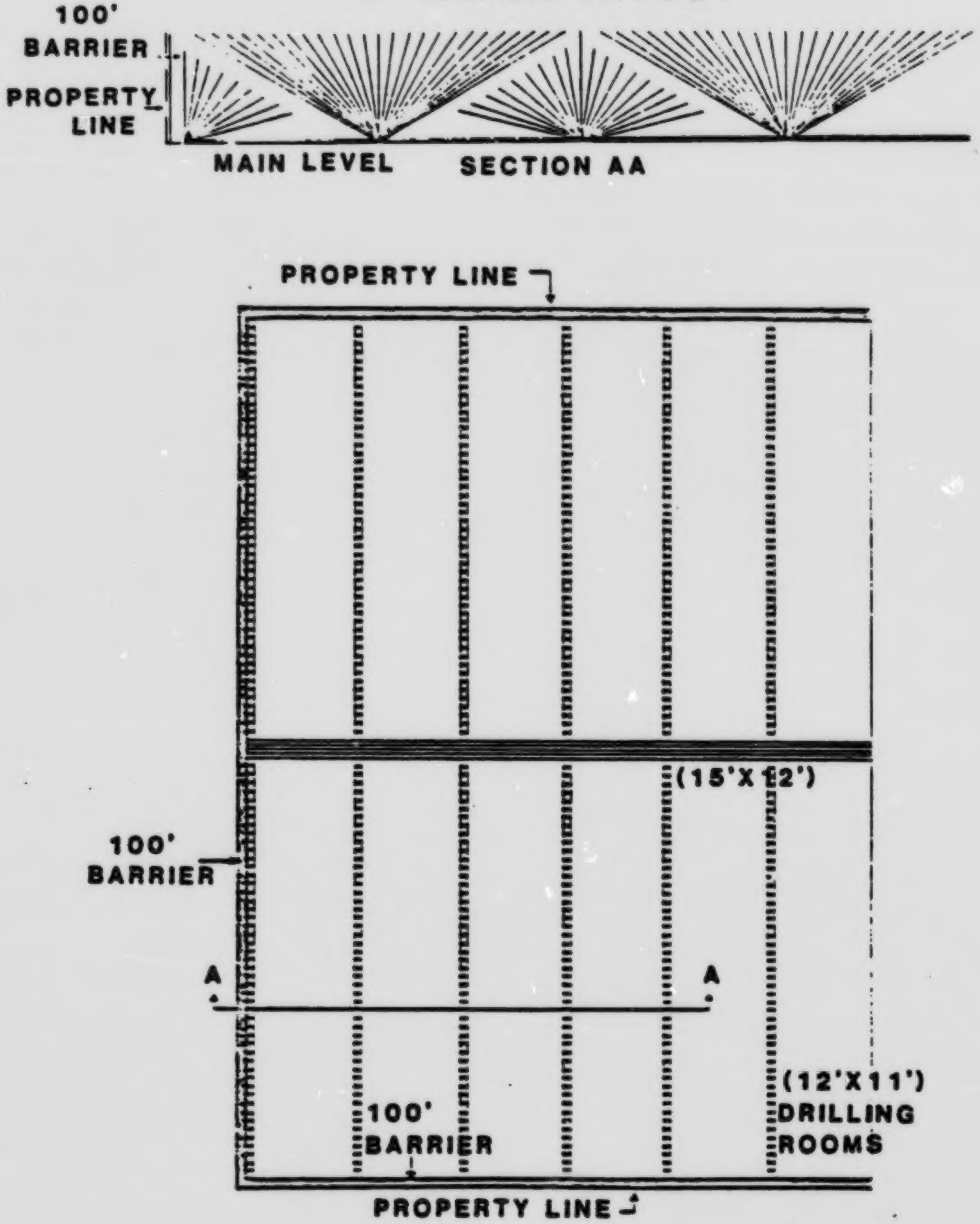

100'
BARRIER
PROPERTY LINE
MAIN LEVEL
SECTION AA
PROPERTY LINE
(15'X 12')
100'
BARRIER
A
A
(12'X11')
DRILLING
ROOMS
100'
BARRIER
PROPERTY LINE

FIGURE 3

GOLDER ASSOCIATES STEAM-ASSISTED LAYOUT

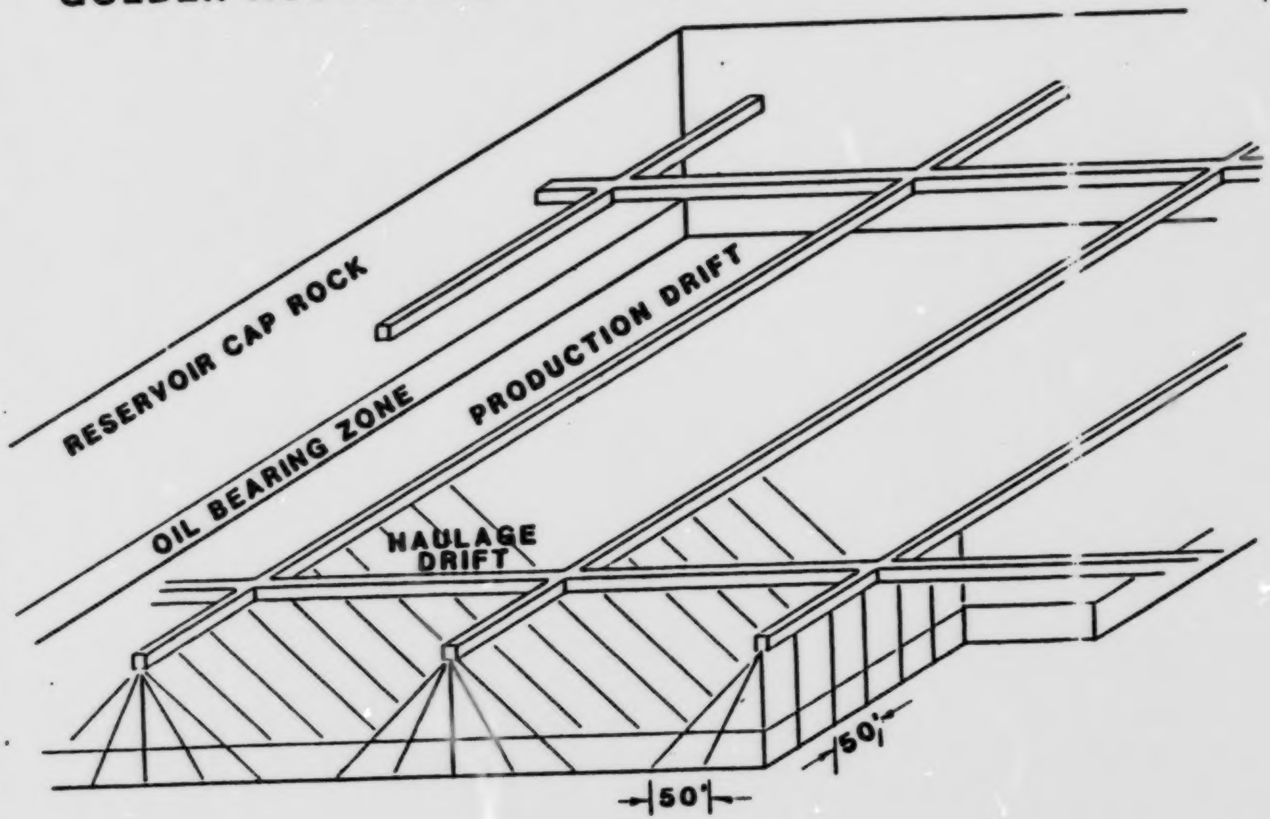

RESERVOIR CAP ROCK
OIL BEARING ZONE
PRODUCTION DRIFT
HAULAGE DRIFT
50'
50'

FIGURE 4

STONE AND WEBSTER STEAM-ASSISTED LAYOUT

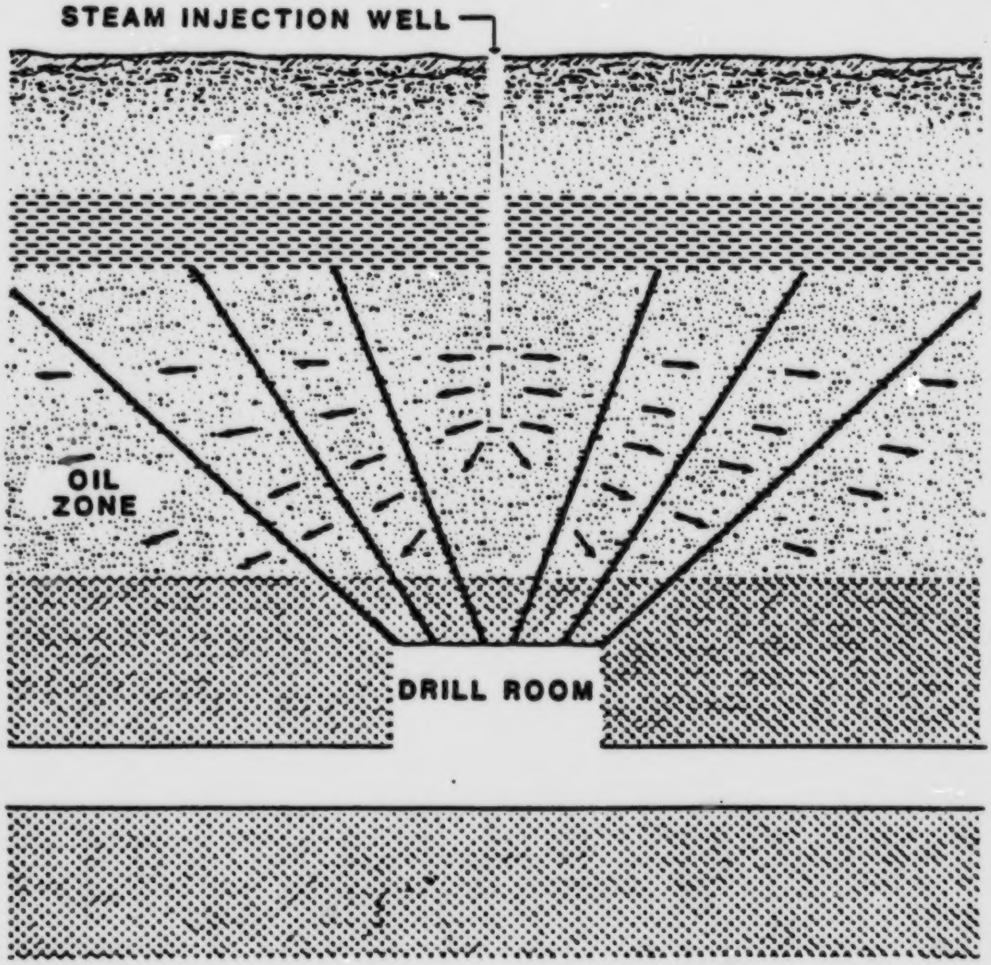

STEAM INJECTION WELL
OIL ZONE
DRILL ROOM

FIGURE 5

HOPCO STEAM-ASSISTED LAYOUT

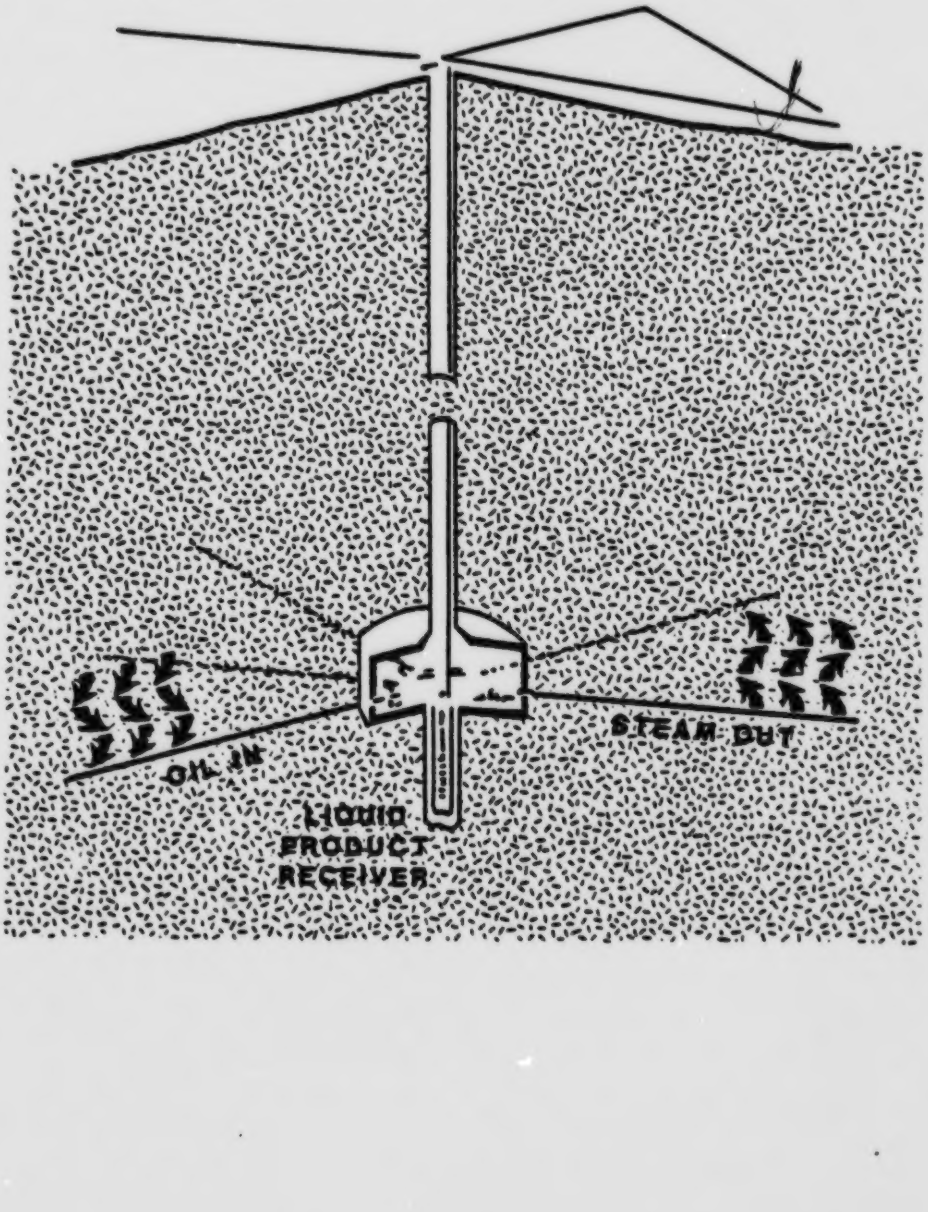

OIL IN
STEAM OUT
LIQUID PRODUCT RECEIVER

FIGURE 6

COMPARATIVE DEVELOPMENT COSTS

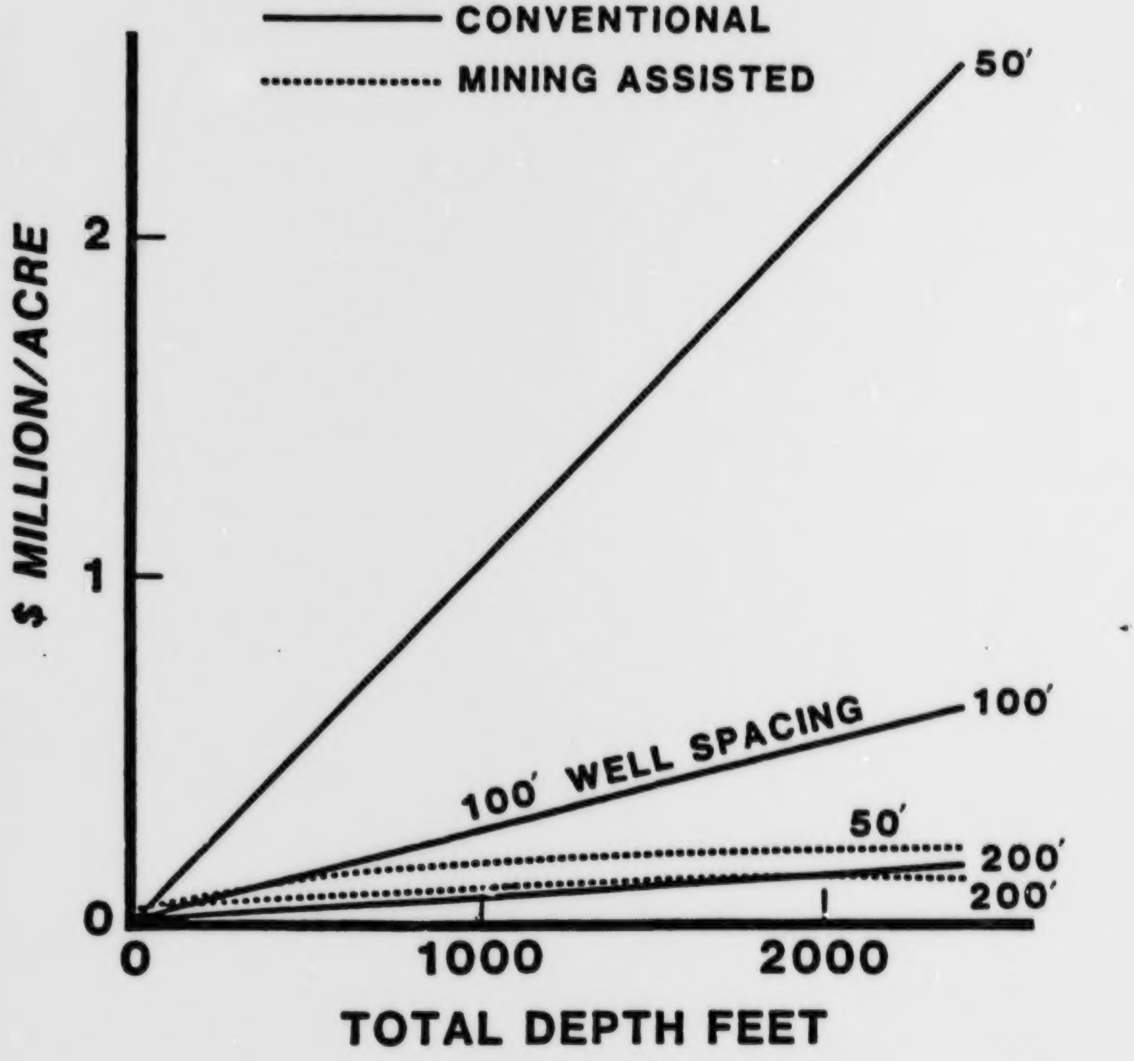


FIGURE 7

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SPE 12787

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Mine-Assisted Heavy Oil Recovery Technology

by T.G. Harding, *BP Exploration Canada*, and S.M. Farouq Ali, *U. of Alberta*
Members SPE-AIME

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This paper was presented at the 1984 California Regional Meeting held in Long Beach, CA, April 11–13, 1984. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write SPE, 6200 North Central Expressway, Drawer 64706, Dallas, Texas 75206 USA. Telex 730989 SPEDAL.

ABSTRACT

A summary is made of technical considerations in underground mine assisted production of oil sand as well as a review of field experience in Canada and the U.S.S.R.

An assessment is made of future prospects for the application of such technology. It is concluded that although the technology exists to construct underground shafts and tunnels, and that mine assisted methods are well suited to certain oil reservoirs, these reservoirs may not be developed in the short term in preference to other more economically attractive projects. It is also concluded that, because of large lead times required for technology development, research and development activities, and in particular piloting work, should continue in the near term in order to establish methods and experience for certain large deposits.

INTRODUCTION

There are many large heavy oil and tar sands deposits in Canada, the United States, Venezuela and the Soviet Union which lie at relatively shallow depths and may be amenable to exploitation through a combination of mining and petroleum production technologies. The development of these known and accessible oil reserves offers advantages over exploration and development in hostile environments such as those of the Canadian Arctic and East Coast Offshore areas. Mine assisted heavy oil production may be the only feasible method for recovering oil in deposits which are too deep to be economically strip mined and yet too shallow to be exploited by normal *in-situ* recovery methods.

Oil production by mine assisted methods would be achieved by sinking a vertical shaft from the surface to the oil producing horizon and constructing tunnels in the reservoir itself or in formations directly above and below the oil-bearing zone. The shafts and tunnels would have to provide safe access for men and equipment at least during the construction and drilling periods. Horizontal or inclined wells changing to horizontal would be drilled from the tunnels into the oil reservoir and these would be used for fluid injection and production. Figure 1 shows a simple schematic of a mine assisted *in-situ* processing (MAISP) scheme for the Athabasaca oil sands.[1] In this deposit, it may be advantageous to construct tunnels in the Devonian limestone directly below the oil bearing McMurray formation because of the more competent nature of the limestone in relation to the reservoir or overburden material.

Conventional mining techniques for oil sands have also been considered.[2,3] Serious questions have been raised, however, about the materials handling requirements and potential economics of such schemes.[4] MAISP would have the advantage over a conventional mining operation of leaving the bulk of the reservoir skeleton in place which would considerably reduce materials handling problems.[5] There would be a need in MAISP to dispose of materials removed during construction of shafts and tunnels and this could possibly be done through transport to existing open pit mines in the case of the Athabasca deposit.[6] Tailings disposal problems of current strip mining and possible conventional underground mining operations would be greatly reduced in MAISP.

Mine assisted techniques for conventional oil production have also been suggested.[7,8] These schemes propose to increase recovery from shallow or depleted fields by gravity drainage into horizontal wells drilled from underground tunnels. In this paper, the application of mine assisted techniques for viscous oil reservoirs is addressed. In these cases, thermal energy is usually applied to reduce oil viscosity and thus promote a significant level of recovery.

In planning a mine assisted heavy oil recovery project, it is necessary to consider a number of subjects which have major implications for shaft and tunnel design. These are summarized for the specific case of mine assisted in-situ processing of Athabasca oil sands. Table 1 lists some of the technical considerations which are discussed in detail in the paper.

References and illustrations at end of paper.

SPE

The limited information available on field experience with MAISP is reviewed. Reports of work in Alberta's oil sands is restricted to the description of the 1963 GCOS test pit[9] and the Saline Creek tunnel.[10] Some information is also available on activities at the Yarega and Baku-area fields in the U.S.S.R.[1,6,11-15,37] A summary of current activity in the Athabasca deposit is also given.[16,20]

DESIGN CONSIDERATIONS FOR ATHABASCA OIL SANDS

Geological

Mossop[21] has reviewed geological considerations in the potential application of MAISP to the Athabasca Oil Sands. Data on the lithology of the oil sands as well as overlying and underlying formations are required. The various lithologies encountered in sinking a shaft from the surface to the oil sand horizon have fundamentally different geotechnical characteristics and will behave differently upon excavation. An understanding of the variations in lithology is obtained from a sufficiently detailed coring and geophysical well logging program in the proposed project area to allow understanding of the depositional environments and therefore the facies patterns.

Variations in bitumen saturation follow patterns of primary porosity and permeability in the Athabasca deposit. It will be necessary to know the quality and heterogeneity of the producing horizon below a proposed site in order to properly evaluate project economics.

The Devonian surface underlying the Lower Cretaceous sediments in which the oil sands are found was subaerially exposed for an extended period of time prior to deposition of the overlying sediments. Considerable topographic relief was developed due to erosion. Up to 20 m (66 ft) of relief has resulted from solution collapse of underlying Middle Devonian evaporites in some parts of the Athabasca deposit. Such regions of structural alteration must be located. The topography of the Devonian surface has implications for excavation of tunnels and the design of tunnel supports in the limestone.

Above massive thick-bedded rich oil sands in the lower third of the McMurray formation are found dipping beds of sand with thin interbeds of shale. The dip of the beds and the strength of the interbeds could have impact on directional control in the drilling of horizontal wells and in support requirements for excavations.

A requirement for planning of a MAISP project is an early, detailed exploration program to identify overburden lithology, reservoir quality and heterogeneity, and the topography of the Devonian surface.

Hydrogeological

The glacial drift and the Grand Rapids formation overlying the producing horizon have average hydraulic conductivities significantly higher than either the McMurray or Clearwater formations.[22] Troublesome amounts of water to underground excavations may be encountered in these formations as well as in zones of low oil saturation in the McMurray formation and in the water-bearing sand at the base of the McMur[illegible] Hydraulic conductivities of the basal water sand a[illegible] usually sufficient to cause concern about heaving floors and piping in subsurface tunnels. Depressurization of these sands ahead of tunnel excavations may be necessary.[3]

Surface deposits range from granular materials to less pervious glacial till.[23] Some preglacial channels which existed on the bedrock surface are filled with granular materials and make excellent aquifers. Sandstone units above the oil sands are usually water-bearing. It is generally conceded that it will be necessary to use freezing techniques during shaft construction in order to control piping failure of excavation walls adjacent to water-bearing formations.[24,25]

Anticipation of disturbances in the McMurray formation due to subsidence caused by solution collapse of evaporites is important to tunnelling operations. Where the Devonian surface has been disturbed by subsidence, and the hydraulic conductivity increased, significant quantities of water would potentially move upward into an excavation in the McMurray formation.[22] It will be necessary to pay attention to the structure of the Paleozoic surface in order that potential weaknesses may be anticipated.

Geomechanical

Of great interest are the geomechanical prope[illegible]ties of the materials encountered in constructing shafts to the oil sand and tunnels in the oil sand or limestone subcrop. Of concern are the resistance of the materials to excavation, their wearing effect on equipment, the stability of the excavations and consequent support requirements, and the behaviour of the oil sand and adjacent formations upon commencement of thermal recovery operations.[26]

The nature of the oil sand materials have been explained by several authors.[27-30] At reservoir conditions, the oil sand may be described as a dense sand with low compressibility and high shear strength. The high shear strength is the result of high dilatancy upon shearing which is due to the highly penetrative nature of the grains.

It is difficult to obtain reliable data on the mechanical properties of oil sand *in-situ* due to sample disturbance problems.[31] The disburtance results from swelling of the material upon stress relief which causes exsolution of gases from the bitumen. The oil sand behaves in an essentially undrained manner and the gases are unable to escape and cause disturbance of the fabric of the material. If stresses are relieved slowly and gases are allowed to diffuse from the material, little disturbance of the fabric occurs.[29] Samples taken from surface outcrops therefore do not suffer the same degree of disturbance as do those obtained from deep deposits. Required project design data include shear strength, compressive strength, cohesion and angle of intern[illegible] friction for frozen and unfrozen materials in the case where freezing techniques are to be employed.[2[illegible]]

It is throught that an excavation will cause the adjacent rock materials to relax sufficiently to relieve hydrostatic pressures.[26] If the surrounding strata are impervious enough, the depressurized state would be maintained. Gas is present in variable quantities in the underground formations and its presence complicates depressurization and ventilation. It will be necessary to collect and vent all gases which enter the excavations. The gases typically have a composition of 80 percent methane and 20 percent carbon dioxide with minor amounts of hydrogen sulphide and heavier hydrocarbons.[3]

When *in-situ* heating commences, the bitumen will expand, a significant change in stress conditions will occur, and the stength of the oil sand will drop if the material fabric is disrupted. Tunnel linings must be designed to withstand high hydrostatic pressures if they are to survive without collapsing during these operations. It may be possible to plan a project such that the tunnels are allowed to collapse once *in-situ* heating begins. In this case tunnel integrity would only have to be maintained during installation of equipment. If tunnels are to be maintained during production operations, then an understanding of the effects of heating and fluid removal on mechanical properties of the reservoir and adjacent formations will be required for proper tunnel design.

Numerical models have recently been developed which address the problem of predicting performance of oil sand materials in a MAISP scheme.[32-34] A program has been written which incorporates both the nonlinear stress-strain behaviour of oil sand and the effects of gas evolution. The program can be used to evaluate the stand-up time of the working face during excavation and the loads which would be imposed on shaft and tunnel supports. A variety of construction techniques can be compared using this model. These would include the effectiveness of advance freezing of water bearing zones, gas depressurization and various support configurations. The model can also be used to establish the probable effects that *in-situ* processes using high temperatures and formation fracturing pressures will have on the loads imposed on shaft and tunnel supports.

Production Engineering

One of the biggest unknowns in conducting economic studies of MAISP is the production performance which can be expected for different well configurations.[1] Some theoretical studies of the gravity drainage of heavy oil during *in-situ* steam heating from horizontal wells have been carried out by various groups using standard numerical simulation models and other more simplified techniques.[34] The model described by Charlwood et al[34] and Byrne et al[33] is noteworthy for its consideration of stress and temperature dependent permeability. Smith and Butler[6] have estimated production performance of 0.05 cubic metres per day per metre of formation for horizontal wells in an oil sand using a steam stimulation technique.

Various options exist for the method of bitumen viscosity reduction in the reservoir. In addition to steam stimulation, processes involving solvents or *in-situ* combustion could be used. New technologies using electrical resistance or electrical induction heating are also considered.[35] Decisions regarding the optimum location for wells in the formation (close to the bottom or nearer the middle) will have to be made. Stephenson[4] suggests that wells should be in the lower part of the formation to take advantage of convection effects.

Some consideration for drilling and completing wells have been discussed by Haston.[1] Pressure control problems could develop if high pressure water zones were encountered at the base of the McMurray formation at Athabasca when drilling upwards from tunnels in the limestone below. The wells would have to be completed to handle sand production which is a problem in the Athabasca deposit. Also, the wells would have to be able to withstand the stresses induced during *in-situ* heating.

Haston has presented the following as a possible well completion. A 10 inch conductor pipe would be sealed to the limestone and rock bolted to the tunnel. The conductor pipe would be equipped with a rotating head and blow out preventers. The water leg would then be penetrated using pressurized drilling mud and a stabilized drill string. A 7.5 inch intermediate casing would be set through the water leg. A 6.75 inch diameter hole would then be drilled for the production string using a pressurized and possibly refrigerated drilling fluid. The production casing would be 4 inch with slots and sand screen. The production of bitumen through slotted liners and sand screens may be a problem and methods may have to be developed to allow production of sand with the reservoir fluids. If oil could be allowed to drain to a central underground pumping facility, significant cost savings could be achieved.[4]

The introduction of heat into the reservoir using steam injection will require, at least initially, formation fracturing pressures. Controlled reservoir fracturing will therefore be an important part of a MAISP project if steam injection is used.[19] A greater understanding of the factors controlling fracture orientation and size will be required for design of well spacing and injection rates. Changes in the stress field due to steam injection at fracture pressures and the consequent changes in fracture orientation and size will be required for design of well spacing and injection rates. Changes in the stress field due to steam injection at fracture pressures and the consequent changes in fracture orientation and dimensions are not well understood.[36] In order to gain a better understanding of fracture propagation phenomena, it will be necessary to develop improved methods of monitoring and modelling of the phenomena. Further uncertainty is introduced into understanding of fracture behaviour by the lack of knowledge regarding the behaviour of oil sand at elevated temperatures.[30]

Environmental

A MAISP project using steam stimulation as a reservoir heating method would require steam generation and bitumen upgrading facilities similar to those proposed for other oil sands *in-situ* recovery projects. Source water for steam generation would likely be obtained for the Athabasca river system in the case of the Athabasca deposit. This river system would also be the discharge route for a portion of the waste water. Recycling of a large portion of the produced water would be required in order to reduce source water and disposal volumes to acceptable levels. A similar water reuse technology to that developed by Esso for the Cold Lake Project could probably be applied at Athabasca. Since a hot water extraction process as currently applied in open pit mines would not be used in MAISP but rather the extraction would be taking place underground, large scale tailings ponds would not be required. There would be a relatively minor disposal problem for produced sand and fines.

As in the case of the Cold Lake Project, disposal water could be separated into two streams with the most offensive waste being disposed of underground and a safe stream being discharged into the river system. In underground disposal of waste water, it would be essential to ensure that groundwater sources were not contaminated.

Noxious gas emissions into the atmosphere would be similar for a MAISP project to those of the Esso Cold Lake Project. Sulphur dioxide is the main pollutant and is produced by burning high sulphur crude or coil in the boilers. Injection of the flue gases along with steam into the reservoir may have some advantages in reducing atmospheric pollution.

One of the main advantages of MAISP may lie in its lack of ground surface disturbance. Both open pit mining and conventional *in-situ* projects involve considerable land surface disturbance. In the case of the Esso project, closely spaced well pads, above ground production and injection lines and access roads to all pads would create significant land surface alteration. Provided that land subsidence is not a serious problem in the oil sands, which it should not be due to their overdensified nature, MAISP should involve little land disturbance.

FIELD EXPERIENCE

1963 GCOS Test Shaft

Hardy and Scott[9] have described the design and construction of a test excavation in 1963 at the location of the present Suncor mine site near Fort McMurray, Alberta. The test was intended to acquire information on the effects of stress relief around the shaft on neighbouring oil sand, gas release and its effect on shaft face stability and seepage pressures encountered by the shaft in water bearing strata.

The shaft was 1.8 by 3.6 metres (6 by 12 feet) and was divided into two compartments, a man way 1.2 by 1.8 metres (4 by 6 feet) and a hoist way. Square timbers were used for support and were spaced 1.2 metres (4 feet) apart in the overburden and 1.0 metres apart (3 feet) in the oil sand. The shaft was sunk by work crews using jackhammers.

Working conditions in the shaft were extremely poor. Water seepage mixing with broken up oil sand turned the whole into a bituminous sand slurry which coated everything it came into contact with. The miners became covered in bitumen and oily sand bo[illegible] inside and outside their rubber suits from bitumen-containing water dripping on them constantly.

Below 18 metres down, the influence of seepage water and slabbing of the shaft face made it extremely difficult to continue operations. The excavation was stopped at a depth of 23.5 metres because it was realized that the shaft could not be successfully completed with the methods being employed. The test confirmed previously expressed theories regarding the strength deterioration of oil sand due to gas release in the pore space upon stress relaxation. It was concluded that water seepage into excavations would have to be controlled and that full linings would be necessary due to short stand-up times of shaft faces. It was also found that weakening of oil sand would not extend to great depths and the high shear strengt of the oil sand would be available for supporting shafts and tunnels if progressive slabbing was prevented by the lining.

Saline Creek Tunnel

Smith et al[10] have described the construction of the first permanent tunnel in oil sand which was constructed in order to divert Saline Creek near Fort McMurray. The creek was causing slope stability problems for the main access highway to the town. The best alternative in solving this problem was to construct a tunnel through an oil sand hill on the east side of the creek.

The tunnel is 107 metres (350 feet) long with about 70 percent of its length being within medium to rich grade oil sand. The tunnel is lined with galvanized steel plate and has a finished diameter of 4.4 metres (14.5 feet).

The oil sand behaved favourably during excavatio with the working face remaining stable and only occasional minor slabbing occurring. Although precautions were taken against tunnel wall instability, the walls remained virtually unsupported during construction and no large scale roof falls or slabbin were observed.

Insignificant swelling and strength reduction were observed since only small amounts of gas were present at this near surface location. Gradual stres relief has allowed the gas to slowly diffuse out of the oil sand without disrupting the interprentrative structure of the grains. The properties and behaviou of oil sand at this location are not thought to be entirely representative of that which would be expected at greater depths. Gas would still be present and significantly greater construction difficulties would be expected in deeper oil sands.

Yarega Field, U.S.S.R.

The Yarega field in the Soviet Union is located near Ukhta about 1300 km (800 mi) northeast of Mosc[illegible] The field was discovered in 1932 and began convent[illegible] al production operations the following year. Rese[illegible] voir and performance data on the field are shown in

Table 2. Conventional development was only able to recover about 2 percent of the oil in place. A mine assisted oil production scheme was initiated in 1937 which raised recovery to a level of 6 to 10 percent of the oil in place by gravity drainage. Steam stimulation was added to the mining scheme beginning in 1968 and resulted in significant improvement in recovery to levels of 40 to 50 percent over a period of about 4 years.

Three basic "Yarega" systems have been developed.[13] In the Ukhta system, tunnels and channels are mined into the cap rock and a dense network of straight shallow production wells 12 cm (4.7 in) in diameter are drilled into the producing formation below. The wells are spaced at 15 to 20 m (49 to 65 ft) intervals. Steam injection wells are drilled to each heat an area of 200 to 300 m^2 (2150 to 3230 $ft)^2$ with steam at pressures of 300 to 400 kPa (43 to 58 psi). The second system involves main access and ventilation tunnels in the cap rock with inclined openings driven downward to the oil reservoir as shown in Figure 2. Chambers are then cut in these inclined openings and low angle wells up to 200 m (650 ft) are drilled radially from the chambers. The ends of the production wells are spaced at no more than 15 m (50 ft) apart. In the third system, main access and ventilation tunnels are bored in the deposits lying below the reservoir. Vertical and slanted wells are drilled from chambers spaced at equal intervals along the tunnels. The crude oil moves into the chambers by gravity drainage. Produced fluids are collected through an open drain system, rough skimming and desanding are done underground, and the production is then pumped to the surface for final treatment.

The tunnels which are used in the Yarega processes are located mostly in a competent tuffite formation located directly above the producing horizon. The oil reservoir is a competent sandstone which does not require support for the walls or roof of tunnels. The introduction of steam into the reservoir must be done carefully so as to avoid steam breakthrough into the excavations. An efficient ventilation system is required to keep underground temperatures in a tolerable range and to remove hydrocarbon vapours emanating from heated oil flowing in an open drainage network. High water-oil ratios, emulsion breaking problems and sand-plugging of production wells have been experienced.

Baku-Area Fields, U.S.S.R.

Plans were made in 1976 to apply technology developed in the Yarega field to the 100 year oil Balakhany field northeast of Baku in Azerbaijan.[12] This field lies at a depth of about 400 m (1312 ft). The Russians have also considered using undersea mining for old offshore fields in the Baku-area and possibly to develop new fields in the Caspian Sea.[13]

Two possible techniques are envisaged for undersea oil mining. The first is applicable to near shore fields and involves sinking two shafts from an on-shore location to a level 60 to 80 m (200 to 260 ft) below the sea bottom. Two horizontal tunnels are then drilled to run the full length of the underlying oil field parrallel to its main axis. The second method is applicable to oil fields further from shore in water no deeper than 100 to 150 m (325 to 500 ft). A vertical structure of reinforced concrete is prefabricated on shore which is tall enough to reach and rest on the sea bottom. Following installation of this structure main access and ventilation shafts are drilled to a depth of 60 to 80 m (200 to 260 ft) below the sea floor and horizontal tunnels bored as in the first case. Undersea mines with access shafts located on shore would be immune to weather conditions and would involve reduced risk of sea pollution. From the standpoint of safety, the Soviets currently consider working levels to be limited to 750 m (2460 ft) for undersea mines.

In 1979, it was reported that belated preparations were underway to drill shafts for the first underground heavy oil mine in Azerbaijan.[4] The plan was for two shafts to be sunk to a depth of 340 m (1115 ft) in the Balakhany field. Originally, plans had called for opening of the first mine in 1978. The shafts and tunnels for this project will penetrate sands and shales and will be susceptible to cave-ins. No mention was made of employing steam injection. Drilling of the first shaft began in late 1980 and it appeared at that time that start-up would not commence until 1982 or 1983.[15]

The Mine Assisted In-Situ Project

The first phase of pilot testing of MAISP in the Athabasca deposit commenced in 1979 and was a surface demonstration test of one of the significant technologies required, the drilling and completion of horizontal wells.[18] PetroCanada, acting as operator for a consortium of companies, completed a three well horizontal drilling test at an outcrop site in the Athabasca river valley at Mildred Lake north of Fort McMurray.[16] A previous report claimed successful completion and stimulation of the wells.[17] The overall objectives of the experiment were to increase confidence in proceeding to an underground test and to obtain data which would be useful in the design of such a test.[18] The steam injection phase of the project was to evaluate 1) effects of thermal expansion of casing, 2) movement of the wellbore during production, 3) the success of the high temperature cement, 4) the amount of sanding, 5) time required for each steam stimulation cycle, 6) the extent of heating, 7) thermal characteristics of the oil sand and 8) the injection and production rates and volumes. Bitumen production was reported to have exceeded expectations and the results looked encouraging for commercial production.[17]

In 1980, Gulf Canada Inc. and the Alberta Oil Sands Technology and Research Authority (AOSTRA) agreed to conduct joint studies to evaluate the feasibility of recovering bitumen from oil sand using MAISP.[19] AOSTRA is currently conducting geological evaluation of a new project site located 17 miles west of the Syncrude facility at Athabasca.[20] This area has an overburden thickness of about 150 m (500 ft). AOSTRA is seeking industry experience and participation for a second level of experimentation and expects to make a decision regarding proceeding with the project by May, 1984. This second stage of pilot work will likely involve an underground test to simulate the conditions of a commercial project.

FUTURE PROSPECTS FOR APPLICATION OF MAISP

The main advantage of MAISP is that a large number of wells can be drilled in the reservoir at a reasonable cost. It is not necessary, as in the case of conventional *in-situ* methods, for each well to be drilled and cased through the overlying ~~foundations~~ mations. Horizontal wells from tunnels contact a much larger portion of the oil reservoir than do wells drilled from the surface. Wells drilled from tunnels provide an efficient means of heating the reservoir and draining heated oil; higher recoveries would therefore be expected. *In-situ* recovery operations using wells from the surface are presently capable of achieving recoveries in oil sands of only 20 to 25 percent which is probably unacceptable in the long run in terms of resource conservation and utilization. Reduced surface land disturbance would also be an advantage of MAISP over strip-mining or conventional *in-situ* operations. If used for near shore subsea exploitation of oil fields, reduced risk of sea pollution also results.

Disadvantages to MAISP include large capital investments, the need for large experimental projects, and the lack of experience with the technology.[6]

Richings[38] has reviewed prospects for oil mining by underground direct methods, surface mining and underground drainage systems. He concluded that the greatest short term potential lies in underground drainage of depleted fields and that future emohasis would be on research activities and small underground drainage schemes.

Petroleum mining in Russia is considered to be marginal even though cheap labour is available.[13] Work has been slowing down in the U.S.S.R. and startup of projects has been delayed in recent years. The Russians may be evaluating developments in tertiary recovery techniques which have potential to be more economically viable.

When considering large viscous oil deposits only the highest grade areas will be developed initially and the most economically attractive methods will be employed. In the Athabasca deposit, MAISP must compete with strip mining operations in high grade oil sand at shallow depths and *in-situ* recovery operations at greater depths. Thermal *in-situ* recovery techniques may be most attractive in parts of the deposits where reservoir conditions are appropriate. MAISP has promise for rich oil sands at intermediate depths but may have to wait until other parts of the resource are developed depending upon the comparative economics. In the mean time, research and development should be directed towards field piloting to develop experience with the method. The collection of geological, geomechanical and reservoir production data will be important for reservoir modelling and refinement of economic analyses.

Considering the large costs and numerous problems associated with *in-situ* exploitation of heavy oil fields and surface development of offshore resources, mine assisted *in-situ* recovery should be evaluated along with other methods for such deposits as those in offshore California, the Alberta oil sands and in hostile environments like those of offshore Alas and the Arctic Islands.[13]

CONCLUSIONS

A number of important studies are required in planning for a mine assisted *in-situ* processing scheme in the Athabasca oil sands. These include geological and hydrogeological description of formations and evaluation of the geomechanical behaviour of underground materials during construction and *in-situ* heating operations. An increased understanding is required of the effects of *in-situ* operations on fracture orientation and stress state since this information will be needed for control of production operations. Reliable predictions of production performance, economic viability and environmental impact will be required.

Considerations of resource conservation and environmental damage provide significant incentives to pursue development of MAISP technology. A tunnel has been successfully constructed at a near surface location in the Alberta oil sands but as yet no deep tunnels have been attempted. It is expected that greater difficulties will be encountered at depth mainly because of swelling of the oil sand due to exsolution of gas upon stress relief. Experiments involving drilling, completion and operation of horizontal wells at a near surface location have been completed and planning for an underground test is underway. The technical feasibility of MAISP has been demonstrated in the Soviet Union but experie is limited in applications to other deposits and the economics have yet to be established. MAISP h good intermediate and long term potential but the short term will likely see only data gathering and piloting activities.

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TABLE 1

DESIGN CONSIDERATIONS FOR MAISP AT ATHABASCA

GEOLOGICAL

- formation lithologies
- depositional environments of the sediments
- reservoir quality and heterogeneity
- topography of the Devonian surface

HYDROGEOLOGICAL

- hydraulic conductivities of formations
- structure of Paleozoic surface

GEOMECHANICAL

- properties of formations
- properties of frozen materials
- effect of heating on properties and stress state

PRODUCTION

- estimates of production performance
- stimulation method
- well drilling and completion techniques
- effects on wells of in-situ operations

ENVIRONMENTAL

- source water for steam generation
- water disposal and reuse
- gaseous emissions of sulphur oxides
- ground surface disturbance

TABLE 2

YAREGA FIELD U.S.S.R

RESERVOIR CHARACTERISTICS

formation type	sandstone
thickness, m	70
depth, m	180-200
initial pressure, psi	220
initial temperature, °F	43
initial oil saturation wt%	7
porosity, %	24
permeability, darcies	3.17
oil specific gravity	0.95
oil viscosity, cp	11,000 to 15,000

FIELD PERFORMANCE

total crude production	2190 bbl/d
steam	3.5 tons/tons of crude
recovery with mining and steam	40-50% of oil in place
recovery with mining	6-10% of oil in place
conventional recovery	2% of oil in place

OIL VISCOSITY[37]

Temp, °C	Viscosity, cp
5	16 080
10	10 060
15	5 374
20	3 420
25	2 175
30	1 380
40	633
100	29.5

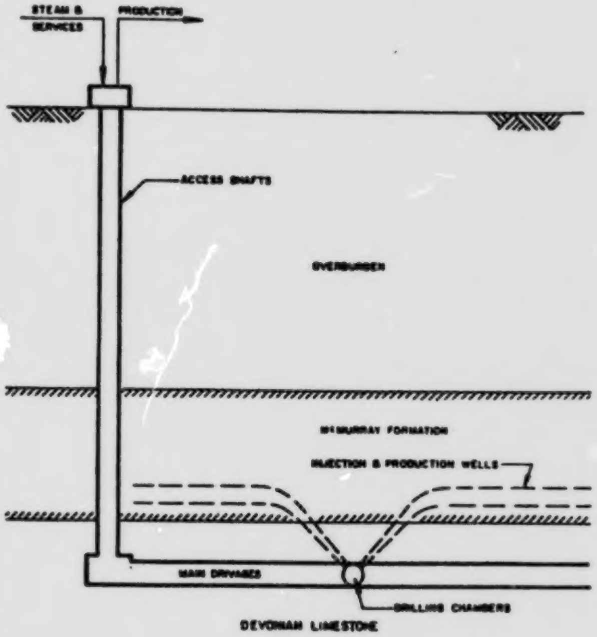
STEAM & SERVICES
PRODUCTION
ACCESS SHAFTS
OVERBURDEN
McMURRAY FORMATION
INJECTION & PRODUCTION WELLS
MAIN DRIVAGES
DRILLING CHAMBERS
DEVONIAN LIMESTONE

FIGURE 1

MAISP SCHEMATIC

(After Haston[1])

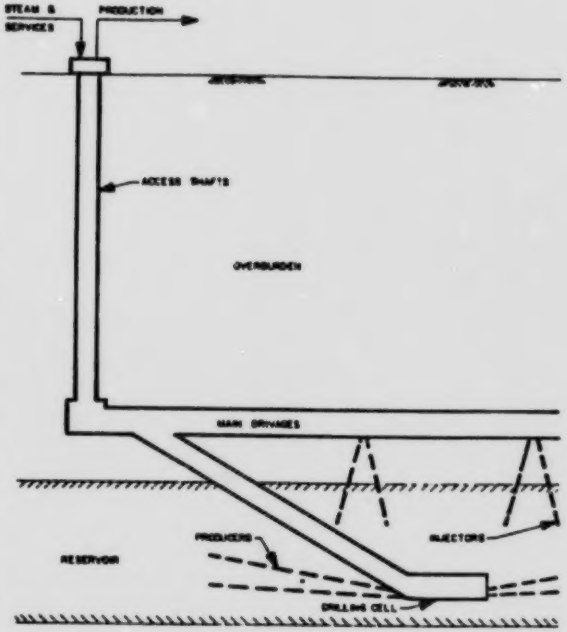
STEAM & SERVICES
PRODUCTION
ACCESS SHAFTS
OVERBURDEN
MAIN DRIVAGES
PRODUCERS
INJECTORS
RESERVOIR
DRILLING CELL

FIGURE 2

YAREGA SCHEMATIC

(After Haston[1])

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Review of Horizontal Drilling Progress

In 1979, Elf Aquitaine and Institut Français du Pétrole (IFP) decided to carry out a research programme called Horizontal drilling technology for enhanced oil recovery *to which the Commission of the European Community provided its financial aid.*
Forhor *is the name of the project.*

Increasing the penetration length through the reservoir by means of near horizontal to horizontal holes is an old idea. Indeed, several advantages, confirmed by numerical reservoir simulations, can be expected, such as :

- Improvement of productivity and increase of final recovery ;
- Reduction of water invasion rate ;
- Possibility to link the vertical ctures ;
- Possible use for steam or chemicals injection.

For fields with little vertical thickness, the productive length of a horizontal well is considerably greater than that of a vertical well. The productivity of a horizontal well increases with its length, although more slowly than this length because a logarithmic pressure-distance law applies. The reservoir engineering studies show that the increase in productivity may regularly attain a factor of 3 to 5. In fields having parallel vertical fractures, a horizontal well drilled perpendicularly to these fractures should cut across a great many of them and thus provide a much greater increase in productivity. In the case of fields with very heterogeneous permeability, such as karstic reservoirs, a horizontal well has a very good chance of crossing highly productive zones.

A study of overall productivity on the scale of the field confirms that, to obtain the same production under uivalent conditions, a horizontal l could replace four vertical wells.

To avoid or delay water or gas influxes during multiphase flow, a horizontal well has two advantages. It can be drilled either near the top of the reservoir or near the bottom so as to obtain as much clearance as possible. Likewise, even with greater total production, production per unit length is less, thus locally causing more moderate stress on the *oil/water* or *oil/gas* interface. The shape of this interface is thus smoother, and calculations show that vertical sweep is more efficient, and hence recovery is greater.

Generally speaking, in multiphase flow, horizontal wells reveal all the more superiority as the mobility ratio is unfavourable (i.e. heavy oil driven by water). The phenomenon to be prevented is the breakthrough of fronts, which occurs all the sooner as flow is unstable. The steadiness of drainage in horizontal wells provides more homogeneous progression to fronts, which is especially advantageous at the beginning of production.

For partly similar reasons, horizontal wells are advantageous for thermal recovery. The exact positioning of an injection casing at a specific depth in a reservoir should enable steam to be fed in easily so that the zone it invades expands steadily, while decreasing heat losses into the surrounding formations.

Lastly, it should be added that horizontal wells, thanks to surprisingly good logging and coring performances, have proven to be extremely valuable instruments for determining the lateral evolution of facies and of fluid distribution in the reservoir.

Drilling horizontal wells. The horizontal drilling is an extension of highly deviated drilling intended to situate a drain of considerable length at a precise depth in a reservoir and with an angle of inclination approaching 90°.

An industrial study performed during the preparation stage of the project revealed a number of conclusions favourable to the feasibility of horizontal drilling.

The second part of the preparatory stage consisted in identifying a number of new problems set by the high inclinations of horizontal wells featuring increased sections of varying importance in the overlay of the reservoir and in the reservoir itself.

The force of gravity, which is preponderant in horizontal drilling, modifies to a certain extent the conventional laws of drilling, hence causing difficulties :

- In running down and retrieving all the equipment : Drill pipes, casings or cables ;
- In preventing and overcoming pipe sticking caused by differential pressure ;
- In cleaning the hole and preventing sediment from the drilling cuttings from forming along the bottom line of the hole drilled ;
- In controlling the weight on the tool and consequently the trajectory followed by the drilling ;
- In cementing the casings.

There are other difficulties besides these, such as allowing for the stability of the walls of the horizontal drain with time and carrying out the electrical operations and completion.

These various problems were subjected to more or less pragmatic study in order to solve them. Tests, in particular those concerning sedimentation of the cuttings, were made in the laboratory. However, apart from a few recommendations, and without the possibility of a base provided by existing models, these studies did result in the conclusion that there was no insuperable *technical snag*.

Accordingly, it was possible to go on to the experimental stage.

Pétrole Informations International, No. 1585, Mar. 25/83

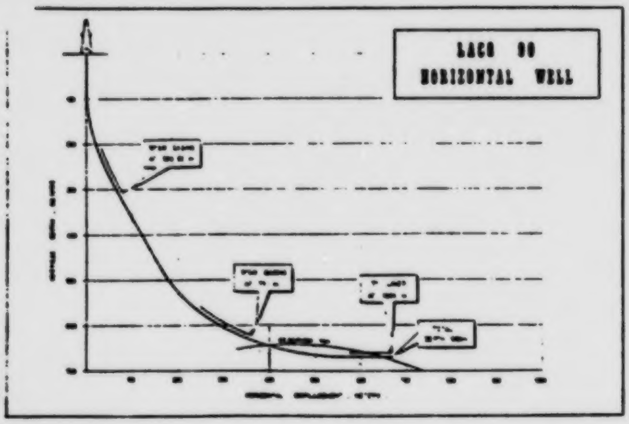

Figure 1

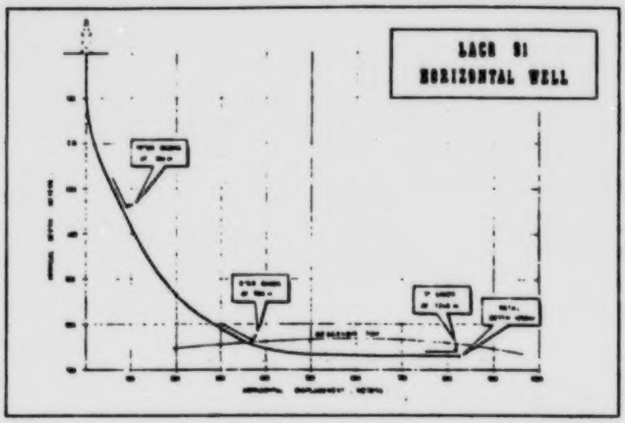

Figure 2

First horizontal well (*LA 90*). The objectives of this initial well were clearly delineated, namely :

- To confirm the overall feasibility of horizontal drilling in a shallow *quiet* deposit ;
- To analyse and solve the new problems encountered during drilling and possibly define the limits of drilling ;
- To obtain an idea of the cost of rizontal drilling.

After examining various possible sites, *Upper Lacq* field in the southwest of France was selected, since this deposit combined the maximum number of both operational and logistic facilities.

The drilling operations took place from May 14 to June 30, 1980, i.e. 44 days. The salient characteristics of these wells are :

- 270 metres drain in the reservoir at an inclination of from 86° to 92° ; depth of horizontal drain : – 670 metres ; total length drilled : 1,086 metres ;
- For an initial test, satisfactory control of problems of trajectometry throughout the profile ;
- Extraction of three horizontal cores in the reservoir ;
- Lowering of a 7" diameter preslotted liner in the horizontal section.

The general cross-section through the well is shown in *figure 1*. The purpose of the casing programme was to solve the problem of the molassic rmations on the surface and then ver the 12 1/4" stage at the point of entry into the reservoir. The 9 5/8" casing was cemented and its shoe laid at an angle of 70°. The trajectory control measurements were made by means of *magnetic single-shot* and *steering-tool* type equipment (*Azintac*).

In all, 95 measurements were needed to monitor the profile.

Several types of bottomhole assemblies were used in the horizontal phase, drilled essentially with a bottomhole motor. As for the electrical operations, after pumping the tool through the drill pipes, a gamma-ray-CCL drilling log was recorded before lowering the 7" preslotted liner.

Second confirmation well *(Lacq 91)*. While at the same time striving to confirm in greater detail the success of *LA 90*, this second well was assigned a number of additional objectives, namely :

- Increasing the length of the drain ;
- Execution of a curtailed programme of drilling logs in the horizontal productive zone, uncased section ;
- Under the proviso of favourable reservoir conditions, cementation of the production liner and perforations ;
- Tests for optimizing the drilling bottomhole assemblies and parameters.

The drilling programme and profile of this second well were kept similar to those of the first so as to avoid introducing new unknown factors (*figure 2*).

This well was drilled in 42 days down to a final depth of 1,250 metres after crossing through 470 metres of the reservoir, of which 370 metres beyond the 90 °.

The objectives set were attained, except for cementation of the 7" liner.

A preslotted liner was therefore lowered. The five cores sampled and the drilling logs recorded provided better knowledge of the configuration of the reservoir. These drilling logs were mainly made by a new method, the *Simphor*, developed by Elf Aquitaine and IFP specifically for horizontal drilling operations.

Like *Lacq 90*, this well was placed on production.

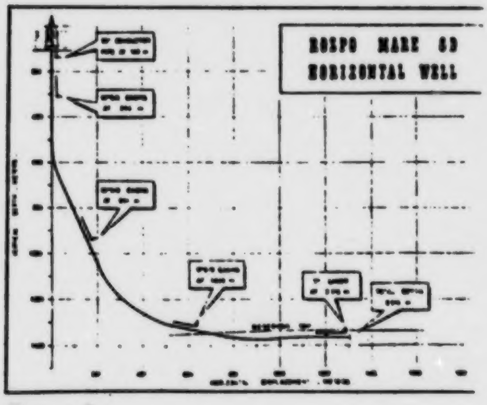

Figure 3

Third drilling *RSM6D : Rospo Mare* (Adriatic offshore). By and large, the satisfactory operations carried out on *LA 90* and *LA 91* as it were paved the way for deeper and more ambitious objectives. The in-

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DRILLING OF HORIZONTAL WELLS

André JOURDAN
Elf-Aquitaine

Horizontal drilling, an extension of highly deviated drilling, is used to improve production by making long drainholes, approximately 90° in inclination, at precise depths in a reservoir.

Drilling deviated wells up to 60° or 70° in inclination does not create any major methodological difficulties. The familiar problems that may be encountered with these wells result mainly from the type of formation being penetrated, and can usually be solved by conventional techniques and equipment.

Although in the United States angles of deviation exceeding 70° are commonly reached, some wells having angles as great as 86°, and although when the Elf-Aquitaine/IFP project was starting up a 90°-well had just been drilled in Canada without too much difficulty, the experience of French oilfield operators in drilling wells up to 80° or 85° in inclination was at that time still relatively modest.

An industry survey made during the preparatory stage of the project made it possible to draw a certain number of positive conclusions regarding the feasibility of horizontal drilling. It seems that although in the past horizontal wells were very rare--almost inexistent, in fact--this was not due to inadequate or impracticable drilling techniques per se. On the contrary, conventional techniques having been sufficiently mastered by the operators involved to allow for angles of up to 80°, there seemed no good reason why angles of 90° or more should not be reached, provided the formation in question lent itself to directional drilling and that all operations were undertaken with very great care.

The second step of the preparatory phase consisted in identifying certain new problems posed by the extreme angles involved in drilling wells with horizontal drainholes, and by the length (usually fairly considerable) of the open holes made in the reservoir and its overlying formations.

The force of gravity, which plays a decisive role in horizontal drilling, naturally modifies conventional drilling laws to a certain extent, and hence creates difficulties in:

- --tripping all types of equipment (drill pipe, casing, cables) in and out;
- --preventing and overcoming differential pressure sticking;
- --cleaning the hole and preventing cuttings from accumulating along the bottom wall of the hole;
- --controlling the bit load and consequently the well path followed;
- --cementing the casing.

To these problems may be added others, such as the stability of the horizontal drainhole walls over time, and the conducting of electrical and completion operations.

So that a solution to these problems might be found, various studies--all more or less pragmatic in nature--were carried out. Some tests, especially those relating to the sedimentation of cuttings, were conducted in the laboratory. However, without existing models to provide a basis, apart from a few precise recommendations,no detailed methodology could be obtained. The studies nonetheless did make it possible to conclude that no insuperable technical "snags" existed, and it was therefore decided to go on to the experimental stage.

The First Horizontal Well: LA 90

The goals set for the first well were clearly defined as follows:

- --to confirm the overall feasibility of horizontal drilling in a shallow, partially depleted reservoir;
- --to analyse and solve the new problems encountered during drilling, and possibly to define the bounds of drilling;
- --to obtain an idea of drilling costs.

After various possible locations were examined, the Lacq Supérieur field was chosen because it combined the greatest number of operational and logistic advantages.

Drilling operations were carried out between May 14 and June 30, 1980--i.e. in 44 days. The salient characteristics of the well are as follows:

- --270-m drainhole penetrating the reservoir at an angle varying from 86° to 92°.
  - Vertical depth: 670 m.
  - Total depth: 1086 m.
- --satisfactory control, for an initial attempt, of problems in plotting the well path that occurred over the entire profile;
- --three horizontal cores cut from the reservoir;
- --perforated liner (7 inches in diameter) run into the horizontal section.

The general outline of the well is shown in Figure 1. The casing program was designed to overcome problems posed by the surface mollassic formations and to cover the 12 1/4-in. phase at the point of entry into the reservoir. The 9 5/8-in. casing was cemented, its shoe set at an angle of 70°. Directional surveys of the well path were made using magnetic single-shot instruments and a wireline steering tool. In all, 95 surveys were required to monitor the profile.

Several types of bottomhole assemblies were used in the horizontal phase, which was drilled mainly with a downhole motor. As for electrical operations, after the logging tool had been pumped through the drill string, a Gamma Ray-CCL log was recorded before the 7-in.liner was run in.

The Second Well: LA 91 (Confirmation Well)

The goals set for the second well, in addition to the objective of confirming the success of LA 90, were as follows:

--to increase drainhole length;
--to carry out a limited logging program in the horizontal open hole;
--to cement and perforate the 7-in. liner, subject to favorable reservoir conditions.
--to optimize drilling parameters and bottomhole assemblies.

So as not to introduce any new unknown factors, the drilling program and profile of the second well were kept the same as those for LA 90 (Figure 2).

The well was drilled in 42 days and reached a total depth of 1250 m, 470 of which passed through the reservoir, including 370 at an inclination of over 90°.

All goals were met except that of cementing the 7-in. liner; a preslotted liner was therefore run in. The five cores taken and the logs recorded provided a better understanding of the reservoir's structural makeup. The logs were conducted using two methods, one of which (the SIMPHOR system) was developed specially by Elf-Aquitaine/IFP for horizontal drilling operations.

Like the Lacq 90 well, LA 91 was brought in. The work that was done to test completion and stimulation methods in horizontal drainholes will be examined further on in this issue.

The Third Well: RSM6D

The satisfactory operations carried out in the LA 90 and LA 91 wells generally paved the way, as it were, for deeper targets and more ambitious goals. The data obtained in relation to cleaning the hole (mud), operations inside the well (friction), transfer of weight onto the bit, and certain stabilized bottomhole assembly arrangements sufficed to encourage drilling in the Rospo Mare field. The main unknown factor remained the type of formation to be crossed--more precisely, its structural makeup (homogeneity) and thus its behavior in relation to the drill string assembly. As we stressed earlier in the article, this "formation" parameter is of capital importance, and may cause the method to fail; also of significance, although perhaps to a lesser extent, are the types of formation that overlie the reservoir and through which the hole must be inclined, if possible, at 80° or more.

The "standard" drilling program followed at Lacq 90 and Lacq 91 thus had to be adapted to meet the new operational requirements involved in a sizeable increase in reservoir depth and total depth drilled. The well profile and the depths at which the different casings were set were determined according to these requirements. The "bottomhole-assembly selection" program was left open so as to allow for adaptation to whatever conditions were met. It was decided to use an MWD device in the 17 1/2-in. and 12 1/4-in. phases. The 9 5/8-in. casing was to be set at an angle of 80°, as near as possible to the reservoir roof (the exact depth of which was not known). As the reservoir was of the karstic variety, complete losses of circulation were to be expected. The estimated tensile stresses involved in tripping the assemblies in and out considerably affected the choice of rig and the grade of pipe to be used.

The well was spudded at the beginning of 1982 and reached a total depth of 2316 m, passing through 606 m of reservoir at angles of 75° to 96°; one section of approximately 370 m was drilled at an angle exceeding 90° (Figure 3). The reservoir roof was located at a vertical depth of 1370 m. Total depth was reached in 71 days; drilling operations from start to finish took 84 days.

Apart from the conventional difficulties encountered in the 17 1/2-in. and 12 1/4-in. phases, the greatest problem naturally consisted in keeping the hole at the intended horizontal depth, which had been determined in advance by the reservoir engineering department.

The forecasts made concerning the heterogeneous behavior of the karstic reservoir were confirmed. Rapid rates of penetration, fissures, and caverns all made it impossible to optimize the bottomhole assembly; consequently, an increased number of trips and directional surveys were required. Nevertheless, corrections made at the proper place and time made it possible to keep the hole inside the reservoir, within an acceptable range of variation in depth.

Eight cores were taken along the well path, and before the 7-in. perforated liner was run in a complete set of electric logs was recorded, mainly with the "SIMPHOR" system tested at LA 91. These logs were as follows:

--in the 9 5/8-in. casing: CBL, GR, CCL.
--in the 8 1/2-in. open hole: ISF, BHC, VDL.

A Gamma Ray-Density Neutron log was also recorded using small-diameter logging tools that were pumped down the drill string out into the open hole.

The well was temporarily plugged; production tests will commence at the end of 1982.

Conclusions

The success of the first three FORHOR horizontal wells demonstrated that it is technically possible to conduct this type of drilling under satisfactory conditions using standard equipment and a special methodology derived from that used with highly slanted wells. If goals set are to be reached, however, perfect preparation and extremely close supervision are more necessary here than anywhere else.

As horizontal drilling cannot yet be considered a routine operation, it would be both premature and difficult to make comparative analyses of drilling time; these three wells, experimental in nature, were designed to demonstrate only the feasibility of the technique, and not to achieve other types of performance.

Analysis of the results will doubtless make it possible in the future to optimize techniques to a certain extent and considerably reduce operating costs.

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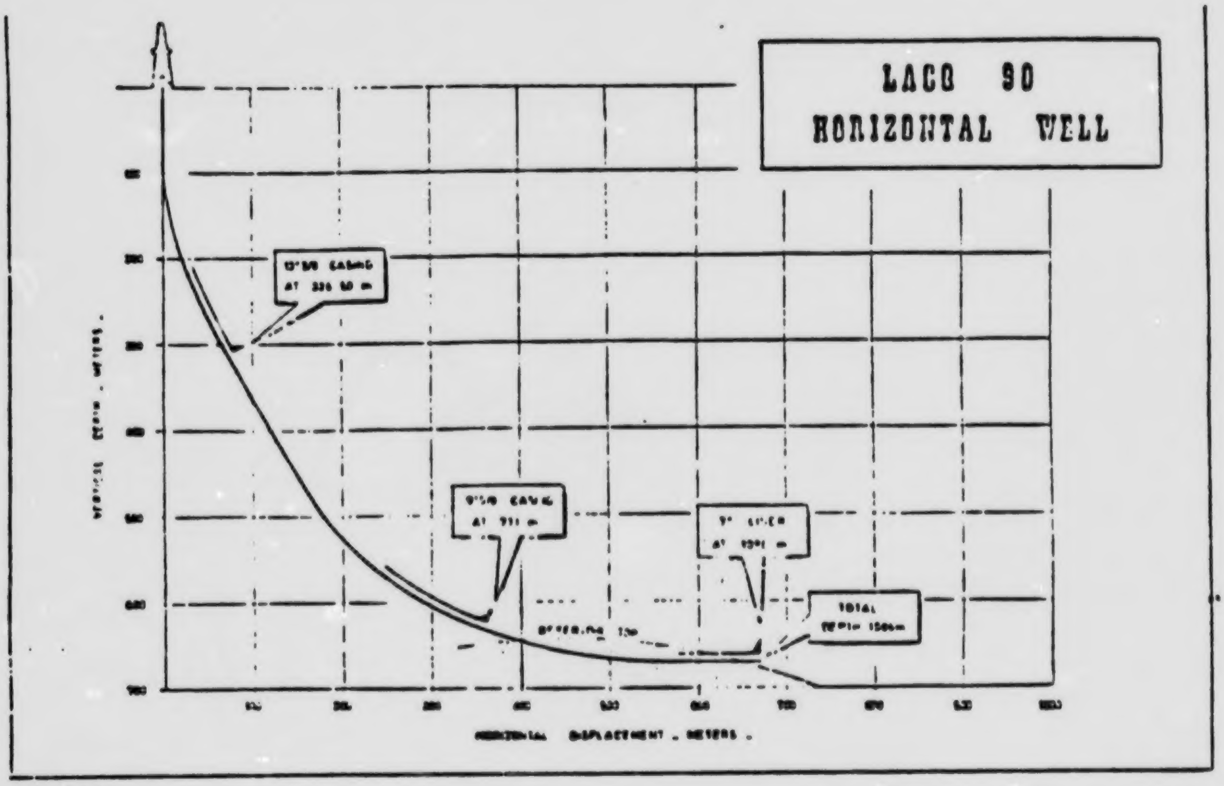

FIGURE 1.

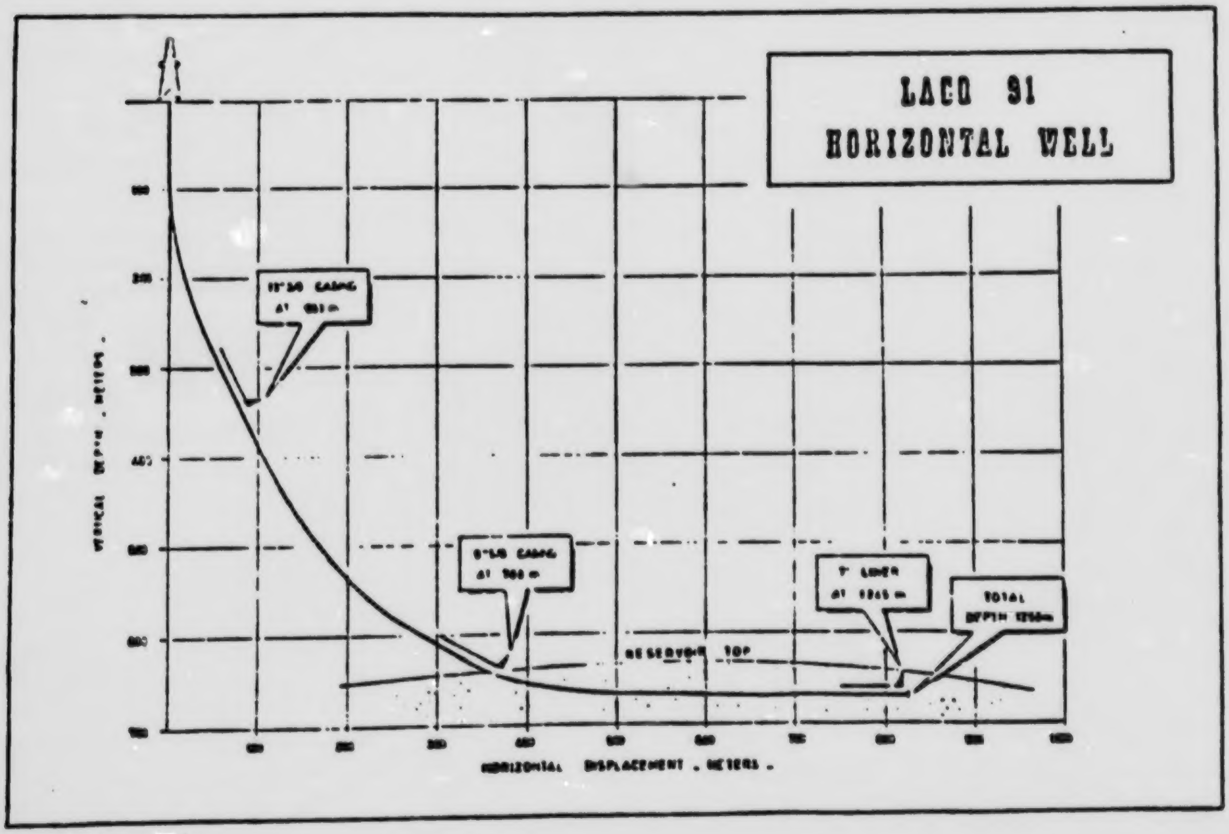

FIGURE 2.

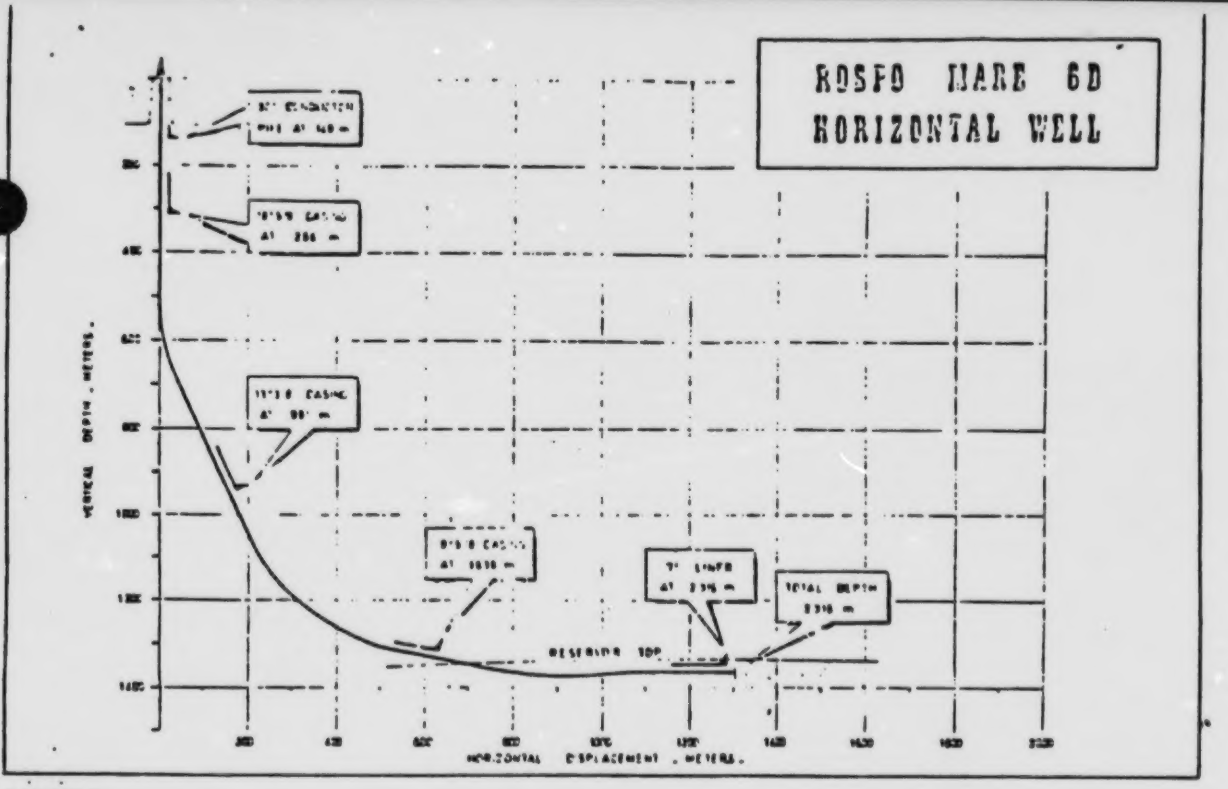
ROSPO MARE 6D
HORIZONTAL WELL
CASING
CASING
RESERVOIR TOP
TOTAL DEPTH
VERTICAL DEPTH, METERS
HORIZONTAL DISPLACEMENT, METERS

FIGURE 3.

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The Reservoir Engineering Aspects of Horizontal Drilling

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This paper was presented at the 59th Annual Technical Conference and Exhibition held in Houston, Texas, September 16–19, 1984. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write SPE, 6200 North Central Expressway, Drawer 64706, Dallas, Texas 75206 USA. Telex 730989 SPEDAL.

ABSTRACT

Elf Aquitaine has drilled four horizontal wells in the past five years: three on land in France are part of a research and development program with the Institut Français du Pétrole; one offshore Italy where Elf is operator for an association which includes Agip.

This paper presents criteria for chosing horizontal rather than conventional wells, and gives simple analytic formulas for the productivity and water coning. Production data collected on the four wells over a period of two to four years confirms these formulas. These criteria have led us to select several new projects for horizontal drilling.

INTRODUCTION

The research project on horizontal drilling carried out by Elf Aquitaine and the Institut Français du Pétrole between 1978 and 1983 was motivated by the problem of developping Rospo Mare, offshore Italy on the Adriatic[1]: viscous oil trapped in a karst formation. This project has led to four wells, three on land in France (two at Lacq, one at Castéra Lou) and one at Rospo Mare where Elf is operator for an association which includes Agip.

The first two wells (Lacq in France) had as primary objective the development of horizontal drilling technology. From then on the main target became additional oil:
- the next well on land (Castéra Lou, France), produces 70 m^3/d of oil (440 BOPD) with no water, eight times more then the neighbouring conventional wells
- the offshore well (Rospo Mare, Italy) peaked at 570 m^3/d (3,600 BOPD), has produced over one million barrels of oil, and its productivity is more then twenty times that of the other wells of the field.

The problem of drilling a horizontal section over 450 m (1,500 ft) long has been mastered in carbonate formations at depths between 600 m (2,000 ft) and 2800 m (9,300 ft). Cores were taken, recovery was good, and a complete set of logs was recorded. One problem still has to be solved: effectively limiting the producing interval to a preselected part of the horizontal section. This is the object of a research project called PRODHOR started this year.

This paper presents the reservoir engineering theory behind horizontal wells which will enable the engineer to decide whether a field is a good candidate for such wells.

We will first evaluate the improvement in productivity in homogeneous, isotropic reservoirs, then the influence of anisotropy. Next we shall study the two phase flow problem, in particular gas and water coning.

These theoretical aspects will lead to criteria for selecting horizontal wells for a particular field application, they will be compared to our case histories, and applied to new projects we are currently evaluating.

THE PRODUCTIVITY OF HORIZONTAL WELLS

Homogeneous and Isotropic Reservoirs

One of the main advantages of horizontal wells is that their productivity is higher than that of conventional wells, particularly when the productivity of the conventional well is low.

The productivity of a conventional well is proportional to the transmissibility (kh = permeability x thickness). Low productivities result from low values of permeability or formation thickness (or both). This can be compensated in horizontal wells where the length L of the horizontal section is not imposed by nature but chosen by the engineer: the kL product in horizontal wells plays a

References and illustrations at end of paper.

quasi-similar role to that of the kh product of conventional wells. This advantage is enhanced in heterogeneous reservoirs where the chances of penetrating a favourable geological feature increase with the distance drilled through the formation, the most favourable case being fractures which are usually vertical and therefore much more likely to be met by an appropriately orientated horizontal well than by vertical wells.

The productivity index of horizontal wells[2,3,4] is given by:

$$PI_H = 2\pi \frac{kL}{\mu} \frac{1}{\frac{L}{h} \ln \frac{1+\sqrt{1-\left(\frac{L}{2r_{eH}}\right)^2}}{\frac{L}{2r_{eH}}} + \ln\left(\frac{h}{2\pi r_{wH}}\right)} \tag{1}$$

The productivity index for vertical wells is:

$$PI_V = \frac{2\pi kh}{\mu} \frac{1}{\ln\left(\frac{r_{ev}}{r_{wv}}\right)} \tag{2}$$

The formulas (1) and (2) are given for use with the SI units. If one wishes to use the following units: ft, bbl, day, psi, md, cp, the multiplication factor including 2π and the use of logarithms of base ten is 0.0145. The multiplication factor including 2π and the use of logarithms of base 10 is 0.0233 with the following units: m, m^3, day, bar, md, cp.

Their ratio PI_H / PI_V is:

$$\frac{PI_H}{PI_V} = \frac{\ln\left(\frac{r_{ev}}{r_{wv}}\right)}{\ln\left(\frac{1+\sqrt{1-{\frac{L}{2r_{eH}}}^{2}}}{\frac{L}{2r_{eH}}}\right) + \frac{h}{L} \ln\left(\frac{h}{2\pi r_{wH}}\right)} \tag{3}$$

The equation (3) is valid in any system of units.

Figures 1 and 2 give a quick graphical solution of Eq.(3).

On Fig. 1, the effect on productivity of the layer thickness results from the ratio h/r_{WH} between layer thickness and horizontal well radius on one side, and from the ratio h/L between layer thickness and productive length on the other side.

For example if:

h = 100 m (328 ft)
L = 270 m (885 ft)
r_{WH} = 0.1 m (4 in.)

The value obtained on the left hand side vertical scale is 2.

Figure 2 gives the ratio PI_H/PI_V of horizontal well versus vertical well productivity. For the above mentioned example, the curve ending at the 2 value on the right hand side vertical scale gives the result depending on the ratio L/r_e between the length of the well and the drainage radius.

The Influence of Anisotropy

The two main causes of reservoir anisotropy are the process of sedimentation and the fracturing which can follow. This anisotropy is usually represented by three permeabilities, k_x, k_y and k_z.

Muskat[5] reduced the one-phase flow problem in anisotropic reservoirs to flow in an "equivalent isotropic" reservoir by dilating the spatial coordinates x, y and z in the ratio $(k/k_i)^{1/2}$ where k is the equivalent isotropic permeability and k_i (i=x,y,z) are the directional permeabilities defined above.

Let us take as example:

L = 500 m (1,640 ft)
h = 40 m (130 ft)
r_{eH} = 1000 m (3,280 ft)
r_{wH} = 0.12 m (5 in. = 0.36 ft)
k_H = 400 md
k_V = 25 md
μ_o = 5 cp

We shall use the symbol ' to represent the isotropic equivalent of this reservoir. The permeability will be:

$$k' = (k_H k_V)^{1/2} = 100 \text{ md}$$

The coefficients which need to be applied to the vertical and horizontal coordinates are:

$$\left(\frac{k'}{k_V}\right)^{1/2} = \left(\frac{100}{25}\right)^{1/2} = 2$$

$$\left(\frac{k'}{k_H}\right)^{1/2} = \left(\frac{100}{400}\right)^{1/2} = 0.5$$

The isotropic equivalent of our example is:

L' = 250 m (820 ft)
h' = 80 m (260 ft)
r'_{eH} = 500 m (1,640 ft)
r'_{WH} = 0.12 m (5 in. = 0.36 ft)
k' = 100 md
μ'_o = 5 cp

Strictly speaking, the transformation of spatial coordinates leads to an elliptic wellbore; the cross sectional surface being inchanged. It can be shown that replacing this theoretical elliptic wellbore by a circular wellbore has a negligeable effect on well productivity.

Equation (1) gives:

PI'_H = 24.2 m^3/(d-bar), 10 bbl/(D-psi)

Had the vertical permeability been the same as horizontal permeability (400 md), the productivity index would have been 70.6 m^3/(d-bar), 30 bbl/(D-psi).

This example shows that vertical anisotropy with $k_V/k_H < 1$ is not in favour of horizontal wells. However when $k_V/k_H > 1$, which is the case for reservoirs with vertical fractures, the productivity of horizontal wells is improved.

HORIZONTAL WELLS AND MULTIPHASE FLOW

Both analytic formulas and mathematical simulations[6] have been used to evaluate the effect of horizontal wells in coning. The main results are as follows:

Coning

Coning is due to the axisymetric deformation of the oil/water interface below a vertical wellbore. It can lead to early breakthrough and low recoveries, particularly when the bottom of the producing interval is close to the oil water contact.

The main parameter in coning problems is the critical rate which results from the equilibrium of viscous forces due to production at the wellbore and gravity forces due to the difference between oil and water densities.

Below the critical rate water will not reach the well and production with remain water free.

No analytic solution has been found for the vertical well. Simulations with both laboratory and mathematical models have led to the empirical formula[7]:

$$Q_{CV} = \beta \frac{k_H \Delta \rho \; h\,(h-h_p)}{\mu_o} \qquad (4)$$

where β = 0.0014 when Q_{CV} is in m^3/d, k_H in md, $\Delta \rho$ in g/cm^3, h and h_p in m, μ_o in cp.
(β = 0.000877 when Q_{CV} is in BOPD, k_H in md, $\Delta \rho$ in g/cm^3, h and h_p in ft, μ_o in cp.

Such equations find practical use in the field after a multiplication constant has been determined which is specific to each set of production wells to allow for the dependency on the heterogeneities of the rock matrix in the immediate vicinity and below the well.

Water Cresting of Horizontal Wells

In multiphase flow problems, horizontal wells have two advantages over vertical wells. First, the higher productivity implies that the same flowrate can be achieved with a smaller drawdown. Second, the horizontal well can be drilled along the top of the formation, and the distance between the producing interval and the oil water contact can be optimized.

The oil-water contact surface and flow of the oil towards a horizontal well at the top of the formation can be analytically studied by the implementation of the hodograph method[8]. If the horizontal well fully crosses a box-shaped compartment of the reservoir with lateral feed, the three-dimensional problem is strictly equivalent to a two-dimensional problem[9,10]. The solution to the problem provides the shape of the water-oil contact and an equation for the critical linear flow:

$$q_c = \frac{k \Delta \rho \; g}{\mu_o} \; \frac{h^2}{L} \qquad (5)$$

or with the practical units, m, d, g/cm^3, cp.

$$q_c = 8.37\ \mathrm{E}{-4} \; \frac{k \Delta \rho}{\mu_o} \; \frac{h^2}{L}$$

The multiplication factor is 1.58 E-3 with the following units: bbl/D, md, g/cm^3, ft, cp:
More sophisticated studies can be carried out by means of using mathematical models, which can evaluate more complex geometries resulting from the geological features of the reservoir, or the position of the horizontal sections of the wells.

WHEN TO DRILL HORIZONTAL WELLS

Since the beginning of this project we have tried to define the conditions under which the performance of horizontal wells will be significantly better than that of conventional wells so as to provide the basis for an economic evaluation of candidates for this type of development.

In the preceeding chapters we have given formulas providing a first estimation of productivity and the critical rate for coning. Recovery has to be evaluated using mathematical models. We have studied many cases which lead to the following guidelines. The possibility of drilling horizontal wells should be evaluated for:

- tight reservoirs especially if vertical fractures are suspected,
- thin beds,
- thin oil columns or a small density difference between water and oil,
- soft formations such as chalk which are liable to collapse.

The improvement in productivity will rarely be more than a factor 5 except, of course, in the case of fractured reservoirs.

FIELD CASES

Lacq Supérieur

This shallow reservoir 600 m (2000 ft) consists of a central area of fractured dolomite, with slightly fractured chalk on the East and West flanks. Oil is relatively viscous (17 cp), and there is a natural water drive. The initial oil column was 100 m (330 ft).

Our first two horizontal wells, Lacq 90 and 91, (Fig. 3) were drilled in the chalky part of the reservoir where after 25 years of production the vertical wells produce more than 98% water. The choice was motivated by practical considerations (well established drilling techniques for this area, shallow wells on land, undersaturated oil).

Lacq 90 was drilled in 1979 on the SE flank and penetrated 270 m (900 ft) of reservoir, the horizontal section of the well being 110 m (360 ft). Three cores were cut in the reservoir and a gamma ray was recorded inside the drill string. The drilling was interrupted when it was found that the wellbore left the formation, which shows that in spite of the large number of wells the structural map of the reservoir was still incertain.

The well was equipped with an uncemented slotted liner and has produced $3m^3$/d of oil (19 BOPD) for the past 4 years, the water cut being 99%. Productivity is three times the average of the surrounding vertical wells, which is what is predicted from theory.

Lacq 91 drilled on the opposite (NW) flank, penetrated 470 m (1,540 ft) the same fissured chalk formation, the horizontal section being 370 m (1,210 ft). Five cores were cut, and the following logs were recorded: dual--induction, gamma-ray, sonic.

These logs confirmed a highly fractured zone, unexpected in this area of the field, where total losses occurred while drilling (Fig. 4): yet another example of the kind of production geology data that can be obtained with horizontal wells.

Production data is complex because the well was used to test various completion techniques. The objective was to isolate the central part where total losses occurred and which produced 100% water, from the two ends. The central part was plugged with a mixture of sand and cement; first an unsuccessfull attempt was made to secure the isolation with two packers. The tail of the well was then equipped with an uncemented pre-perforated liner and finally the central part and the head were cemented. The tail was then produced alone and the water cut was the lowest of all wells in the field (93%). Unfortunately an accident led to the well being closed after six months. Later on, this well has been put again to production.

The results showed that it was essential to develop techniques to isolate sections of horizontal wells.

Castéra Lou

Castéra Lou 110 (CLU 110) was the last well drilled as part of our research project, and its objectives were to demonstrate that it is possible to drill horizontally at a depth of 2,800 m (9,000 ft), to experiment with selective completion techniques, and to confirm that the productivity of a horizontal well could be higher than that of its neighbours.

The reservoir of Castéra Lou, also called Brêche de Garlin, consists of a slightly fractured dolomite at a depth of 2 800 m (9,000 ft). The oil is undersatured (bubble point of 128 bars (1,850 psi)) and its viscosity is relatively low (1.4 cp). The oil column is 50 m (160 ft) and there is bottom water.

The vertical wells have been on production for 4 years, producing about $8m^3$/D of oil (50 BOPD) with a water cut higher than 70%.

CLU 110 penetrated 330 m (1,000 ft) of reservoir, the horizontal section being 162 m (490 ft). The last few metres of the well penetrated a very highly fractured zone, believed to be associated with a major N.S. fault, with total losses. The well therefore consists of two segments: 311 m (940 ft) of very slightly fractured dolomite and 20 m (60 ft) of highly fractured reservoirs.

An attempt to isolate the segments using packers was only partly successfull: they were set but the seals failed.

The well now produces the slightly fractured dolomite through a pre-perforated, uncemented liner, the fractured zone having been plugged while drilling. The well is pumped at 70 m^3/d of oil (440 BOPD) with no water, an improvement over neighboring vertical wells by a factor 8 if only oil production is taken into account, or 2,3 if oil and water are included.

The highly fractured section does not produce: it was plugged while drilling, but it is planned to stimulate it and put it on production at a later date.

A study of the well bore shape in the neighbouring vertical wells, and of the shape of the highly deviated (80°) part of CLU 110, has shown that the fractures in the slightly fractured dolomite are probably parallel to the horizontal well. This type of study gives important clues as to the direction the horizontal well should take so as to meet a maximum number of fractures.

CLU 110 is a good illustration of the possibility of increasing production and recovery where vertical wells are liable to water coning.

Rospo Mare

The horizontal well Rospo Mare 6 (RSM6) has been drilled based on economic considerations only: the development of a major offshore European field.

The reservoir is situated at 1370 m (4,500 ft) subsea; it consists of karsts, which are a compact carbonate rock whose porosity is so low that oil has not been able to penetrate the matrix. The oil is contained in the fractures and vugs of the karstic system, vugs ranging from a few centimetres to caverns.

The oil is heavy 11°API (density 0.993 g/cm^3), viscous (300 cp), undersaturated. The oil column is 100 m (330 ft) and oil in place is 100 millions tons.

The research project on horizontal wells started with the idea that vertical wells could not produce a field such as Rospo Mare because of coning; this led to the concept of drilling long horizontal wells at the very top of the reservoir. It was hoped that the horizontal well would have a sufficiently high productivity because of the large number of karstic voids and fractures that it would cross to have a minimal drawdown. The WOC would then rise slowly without the local deformations induced by the high drawdowns near vertical wells.

It was decided to start with a pilot consisting of a platform from which would be drilled a vertical and a deviated well penetrating 30 m (100 ft) of reservoir (final depth being 70 m (230 ft) above the WOC), and a horizontal well 70 m (230 ft) above the WOC. The horizontal well, RSM6, penetrated 600 m (2,000 ft) of reservoir including a section of about 370 m (1,200 ft) beyond the 90° point. Eight cores were sampled. The logs recorded were:

- in the 9 5/8-in. phase:
Cement Bond Logging (CBL), Gamma Ray (GR), Casing Collar Locator (CCL)

- in the 8 1/2-in open hole:
Borehole Compensated Induction Sonic (BHL-ISF), Variable Density Log (VDL), Gamma Ray (GR), Borehole Geometry Tool (BGT), Dual Laterolog (DLL).

A density Neutron Gamma Ray log was also recorded using small diameter tools pumped through the drillpipes run in the uncased zone.

The production geology data was invaluable (Fig. 5): and in particular it was shown that there were valleys folled with shale: this is of major importance in any future development which must avoid such areas.

The pilot was put on stream in 1982, and results as at June 1st 1984 are given in Table 1 and Fig. 6.

The wellrates have all been adjusted to the critical rate for coning, partly to avoid the problem of separating water from oil (offshore on a pilot installation) or penalties at the refinery, partly to avoid an excessive decline in production.

The results of the pilot have confirmed the advantages of horizontal wells on Rospo Mare, several more being envisaged, and could lead to a generalisation to other karstic reservoirs.

Another aspect of RSM6 is that it shows how horizontal wells have more chances of penetrating geological features favourable to high productivities, and therefore a better sweep efficiency where coning is to be avoided.

TECHNICAL DATA ON THE WELLS

Technology

The four horizontal wells have been drilled with 100% of success [1], reaching the target in the reservoir within a pretty good accuracy (Fig.3).

Conventional equipments and methods were used to perform these drilling operations but special attention was given to drilling mode, mud characteristics, drill string assemblies, deviation surveys and well profiles. High quality supervision was also the key to success.

Drilling time is now somewhat like 2 to 3 times the time required to reach the same reservoir with a vertical well. As a consequence, costs ratio of these wells are in the range of 2.4 to 3.5 depending on vertical depth and logistics.

As far as reservoir investigation is concerned, cores have been cut with good recovery, and logging operations performed essentially with the SIMPHOR technique [11] but also with the "pumped out" technique.

In the field of completion, two methods have been tested, the external casing packers system and the conventional cementing--perforation method. Both methods were used with partial success. A new research and development project has been set up to implement this area.

New Projects

The main projects are:
- a tight sour gas reservoir 4500 m (15,000 ft) below the town of Pau: the objective is two fold, to reach the target with the rig outside the urban area because of environment problems, and to penetrate a maximum number of vertical fissures.

- a second horizontal well at Castéra Lou, both for production and appraisal purposes.

- the development of the Rospo Mare field

- a horizontal well at the base of a tight oil reservoir where a secondary gas cap is expected to form.

Other projects are under study: they concern tight gas, or are motivated by the problem of avoiding coning. These projects are under study because they correspond to the criteria set out above, but it should be born in mind that horizontal wells are a new concept; even though the productivities of Castéra Lou and Rospo Mare show that it has become a reality, each candidate must be evaluated individually.

CONCLUSIONS

- Whilst horizontal drilling would not appear to be capable of providing an universal method, several specific themes conducive to its implementation are analyzed.

- Quick analytic methods are proposed to evaluate initial productivity index and critical production rate of a horizontal well.

- Industrial experience proves the feasibility at reasonable cost of drilling, coring, logging, completing and producing horizontal wells.

- Discussion of production results of our four horizontal wells proves their economic interest.

- New projects induced by the former good results are described.

NOMENCLATURE

D = distance between two lines of horizontal wells

g = acceleration of gravity

h = thickness of the reservoir

k = permeability of the porous media

L = length of the horizontal well

ln = Napierian logarithm

log = decimal logarithm

PI = productivity index

q = linear production rate of a horizontal well

Q = production rate

r = radius

Greek

Δ = difference

Δp = production drawdown

μ = viscosity

ρ = density

Subscripts and Superscripts

c = critical

e = external (drainage)

F = fissure

H = horizontal

o = oil

p = perforated

V = vertical

w = well

x = along the x axis

y = along the y axis

z = along the z axis

' = equivalent problem

AKNOWLEDGEMENTS

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TABLE 1

ROSPO MARE PILOT PRODUCTION DATA

WELL	MAXIMUM RATE	PRESENT RATE	CUMULATIVE OIL
RSM4 VERTICAL	200 m^3/d (1,250 bbl/D)	100 m^3/d (625 bbl/D)	70 000 m^3 435,000 bbl
RSM5 SLANTED	48 m^3/d (300 bbl/D)	0 m^3/d (0 bbl/D)	13 000 m^3 81,000 bbl
RSM6 HORIZONTAL	570 m^3/d (3,600 bbl/D)	320 m^3/d (2,000 bbl/D)	203 000 m^3 1,270,000 bbl

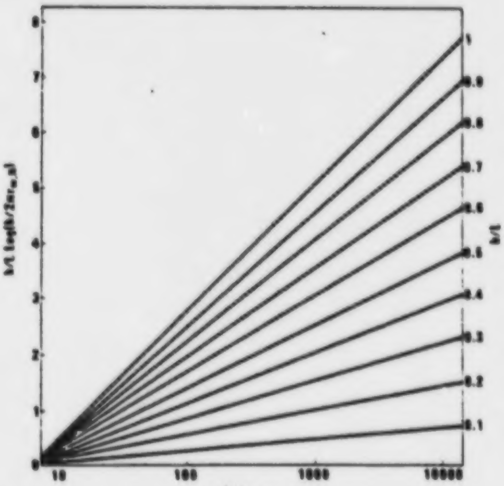


Fig.1 Influence of the layer thickness on productivity formula

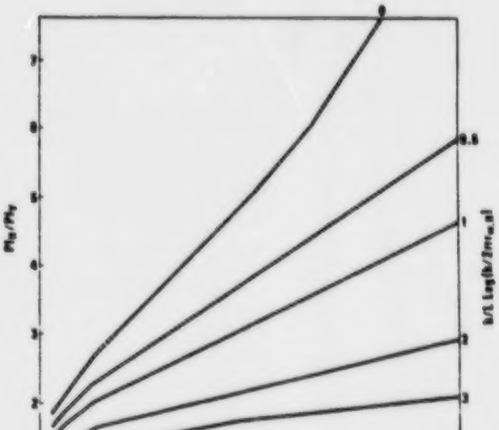
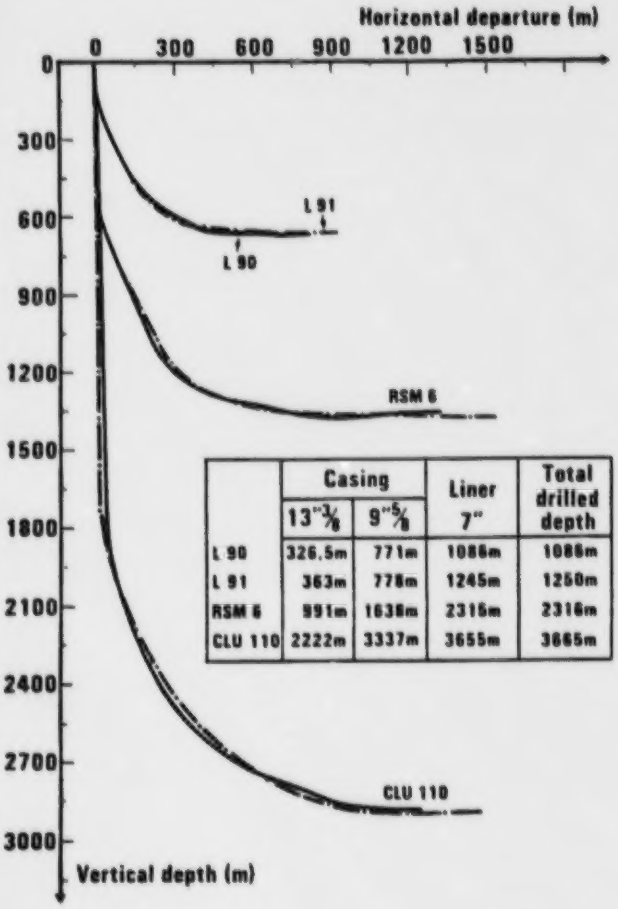


Fig.2 Productivity ratio of horizontal wells versus vertical ones



	Casing		Liner	Total drilled depth
	13"3/8	9"5/8	7"	
L 90	326.5m	771m	1086m	1086m
L 91	363m	778m	1245m	1250m
RSM 6	991m	1638m	2315m	2316m
CLU 110	2222m	3337m	3655m	3665m

Fig.3 Profiles of the four horizontal wells

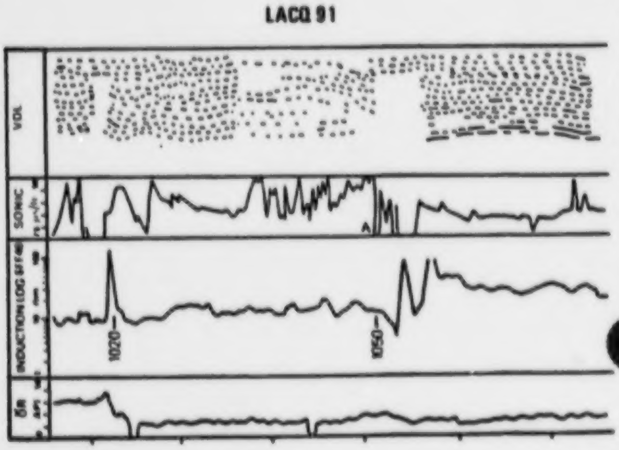


Fig.4 Fissured zone evidenced on the logs in the Lacq 91 horizontal well

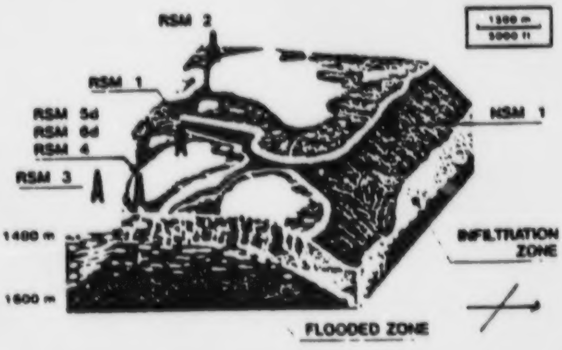

RSM 2
1500 m
5000 ft
RSM 1
RSM 5d
RSM 6d
RSM 4
RSM 3
RSM 1
1400 m
1600 m
INFILTRATION ZONE
FLOODED ZONE

Fig.5 Geology of the Rospo Mare field

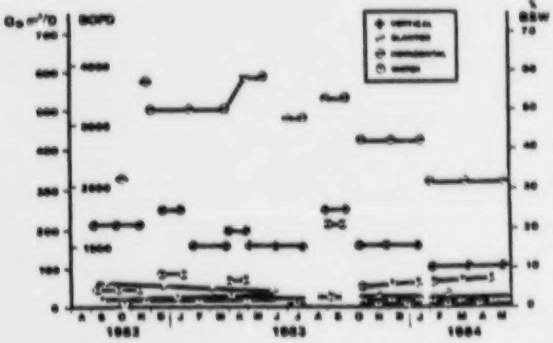


Fig.6 Rospo Mare Wells production profiles

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[illegible] OIL SANDS
INFORMATION CENTRE

⑫

PURPOSE OF HORIZONTAL DRILLING,
OIL FIELD CONSIDERATION

by

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Institute Francais du Petrole

From: Petrole et Techniques, No. 249,
pp. 33-44 (December, 1982)

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HORIZONTAL DRILLING: FIRST ACHIEVEMENTS IN EUROPE

The latest news of a first:

Rospo 6, first horizontal well that was ever drilled offshore, has just been put into experimental [or test] production.

Its productivity is more than 10 times better than that of vertical wells, or even slanted ones, which have already been drilled on this heavy oil field, that is fractured, karstic, meaning that its development is difficult.

Latest production of Rospo 6:600 m^3/d of oil

To be continued....

PURPOSE OF HORIZONTAL DRILLING, OIL FIELD CONSIDERATION.

By Herbert REISS (SNEA(P)
and Francois GIGER I.F.P.

From: Petrole et techniques No. 294, December 1982, pp.33-44

Three horizontal wells have been drilled recently by the Partnership Elf-Aquitaine/I.F.P., of which two on land (Lacq Superieur, France) and one at sea (Rospo Mare, Italy).

The recommended intervals of this technology have been determined (fractured deposits, rather thin banks, thick oil, intercalary oil or fringing [border] oil, estimate of the lateral evolution of the facies).

Up to now the drilling, core sampling, measuring problems have been solved in a satisfactory manner. With regard to the completion of these huge drains (500 meters that are almost horizontsl at Rospo Mare), studies and operations are being carried out within the framework of this scientific and technical research effort.

HORIZONTAL DRILLING

FIRST ACHIEVEMENTS IN EUROPE

INTRODUCTION

To develop in Europe a large, very viscous oil field that is relatively thin in spite of a very active aquifer that is likely to submerge rapidly through the cracks the vertical wells that are being contemplated...Missions that seem almost impossible, but how motivating! This is how the idea originated to drill horizontal drains close to the super incumbent stratum of the reservoir and whose lateral extension would make it possible to reach an important productivity by cutting across [or intercepting] numerous cracks.

The discovery of the Rospo Mare, in the Italian Adriatic Sea, has thus formented recourse to the concept of horizontal drilling which had inspired several attempts over almost the last 50 years of the petroleum industry: achievement of radiating wells drilled from a mine shaft in the 1940's in the United States [1] and of branched wells drilled in the Soviet Union in the 1950's over old fields in order to increase their productivity [2&3].

More recently, the usefulness of horizontal wells has been clearly shown in the United States in order to avoid gas coning [4,5&6] and in Canada, within the framework of the Cold Lake project, in order to install at the bottom of a reservoir of very thick oil heating ramps by steam injection, even to reach a very distant objective.

The determination to make the Rospo Mare Field productive and, in general, the desire to improve the productivity of the wells and the sweeping of the reservoirs, have led to the establishment of a scientific and technical research project. This project is led by the partnership between a scientific research entity, the French Petroleum Institute, and an industrial operator, the National Enterprise ELF-Aquitaine. With the support of the European economic community (C.E.E.) and a financial backing of approximately 50 million francs distributed over a five year period, this effort has already resulted in the drilling of three horizontal wells of which two are in France on the upper Lacq Field and one, which is a first in the world, at Rospo Mare offshore the coast of Italy.

THE DEPOSIT MOTIVATIONS

Reservoir research studies made at the start of the project, together with the determination of possible technological obstacles, were aimed at listing cases where horizontal drilling is to be recommended.

First, the needs expressed and the know-how of the industry have been determined through bibliography and various contacts. Besides the extra cost of drilling, another obstacle that has not yet been overcome appeared, namely the "completion" of wells in a selective manner. Then computations were undertaken. Following the lead of the Soviet authors, the gain in productivity and deformation of the separation surfaces between fluids have been determined, namely, in an analytic way. Specific numerical models with a very low cost of utilization making possible numerous simulations have been prepared to specify in particular the displacement of fronts and increase in sweeping.

If horizontal drilling does not seem to provide a universal process, to be favorably started everywhere, three specific instances are propitious to its implementation. They are the production of reservoirs containing heavy oil or with little thickness and improvement of the multi-phase production mechanisms: water or gas coning, sweep and thermal recovery. It is also in competition with hydraulic fracturing, specially in a chalk formation whose malleability prevent the propping agents from maintaining the fracture open.

The cracked reservoirs, due to their depth of several hundred meters or more, show vertical or sub-vertical cracks or fissures. They generally consist of a very hard, brittle rock with little permeability and permitting flows only in accordance with the network of cracks or fissures. If these are rare and spaced, the comparison between vertical and horizontal wells is expressed in terms of probability to recover them. Vertical wells which will only meet few cracks, and sometimes none, shall be low producers, or even dry holes. They will then be surpassed by horizontal wells which will probably come across many cracks, specially if it is possible to place them perpendicularly to their preferential direction after having determined it. The gains in productivity to be expected are important. The same gains can probably be obtained for other heterogeneities than cracking, for example, the lenses of facies one tries to find at the time of intercalary oil or fringing oil production.

For thin homogeneous deposits the productive length of a horizontal well is not limited before hand whereas a vertical well is limited by the thickness of the layer. However, it must be stated that productivity increases much more slowly than the productive length (logarithmic equation). If one refers to Figure 1 which illustrates the theoretical computations whose justification can be found in references 7,8, and 9, it appears that the gain in productivity can reach from 3 to 5. In chalk formation, where poor collapse occurs with considerable removals (or withdrawal) the productivity increase can be taken advantage of in order to reach a profitable well production without exceeding acceptable constraints for the rocks. Nevertheless, if permeability is not isotrope, a Kv/Kh high ratio is unfavorable for a horizontal well. In a production flow sheet with several radiating wells it appears (Figure 1) that not much is to be gained by increasing their number. In order to make possible a comparison of cost with the use of conventional vertical wells, a reflection has been conducted regarding global productivity of the field, which involves simultaneously the geometry of the producing wells and their spacing [10]. It confirms that in order to obtain the same production in similar conditions, the utilization of horizontal drains makes it possible to divide the number by a factor on the order of four. On the theoretical level, the gain can be even more considerable for very thin producing banks. However, in this hypothesis, the profitability of bringing in the bed is not certain.

The economic advantage of horizontal drains depends obviously on overcoming the excessive drilling cost and equipment cost in comparison with those incurred for vertical wells.

With regard to the multiple phase production mechanisms, horizontal wells show a superiority which becomes more evident as the mobility ratio is unfavorable, for example, heavy oil swept by water. The adverse phenomenon is indeed the drilling of fronts which occurs early on when flow is unstable. Drainage regularity between horizontal drains brings a more homogeneous progression of fronts, which is particularly advantageous at the start of production, as shown by Figure 2. This can be taken advantage of in thermal recovery where the exact positioning of an injection ramp (or tube) in the reservoir makes it possible to introduce steam easily; Esso and Texaco have tried it at the foot of the Tar Sands (bituminous sands) of Cold Lake in Canada [5&6]. As to the surface sweeping of oil by the injected fluid, its efficiency reaches 90% as soon as the horizontal extension of each one of the wells of the row reaches 60% of their longitudinal spacing (fluids of the same viscosity).

To fight water coning the horizontal well has two advantages. It is possible to locate it on top of the deposit (reservoir) in order to obtain the largest retention of water. Moreover, even with a superior total production, the linear production, or production by unit of lengths, is lower entailing locally a more moderate demand on the separation surface oil/water. The shape of the latter is thus softer (see figure 3) and vertical sweeping is more effective in drilling.

In horizontal drilling, just as in vertical drilling, the more specific data one obtains the better knowledge of the reservoir becomes. It is for this reason that special techniques for setting up measuring probes have been developed for horizontal wells. On one hand it is a matter of pumping in the drill string of reduced diameter which emerge in line with the uncovered area (Schlumberger process) and on the other hand passage of the drill string of standard diameter at the end of the pipes. The electrical connection with the surface is then assured thanks to a process developed within the project (see below on page 42 the Simphor process). Nowadays, practically all of the available well loggings can be recorded on horizontal wells (at Rospo Mare, CBL, GR, CCL are available in the casing string, ISF, BHC, VDL, GR, DLL, BGT in the open hole. The quality is excellent, as attested by figure 4 where a cracked area can be seen clearly (*), a capital event for the study of the deposit. Combined with corings, these well logs supply new extremely interesting data about the deposits (reservoirs). They make it possible indeed for the first time to establish horizontal sections and to specify the lateral variations of the facies and the distribution of hydrocarbons and this was done all the better since numerous core samples were taken without problem on three horizontal wells drilled up to know.

Finally, in their "intervals" (?), considering the productivity and the sweep, horizontal wells can become five times better than vertical wells, and even more so in the case of cracked or fractured deposits. Moreover, from the point of view of measurements, well loggings and core sampling have been practiced with great satisfactory results. Finally, they open new possibilities to the evaluation of the lateral evolution of the facies.

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*It is true that it was a matter of detecting an area with total losses whose cracks have enormous openings since they were able to absorb several tons of sand.

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*In-house Communication

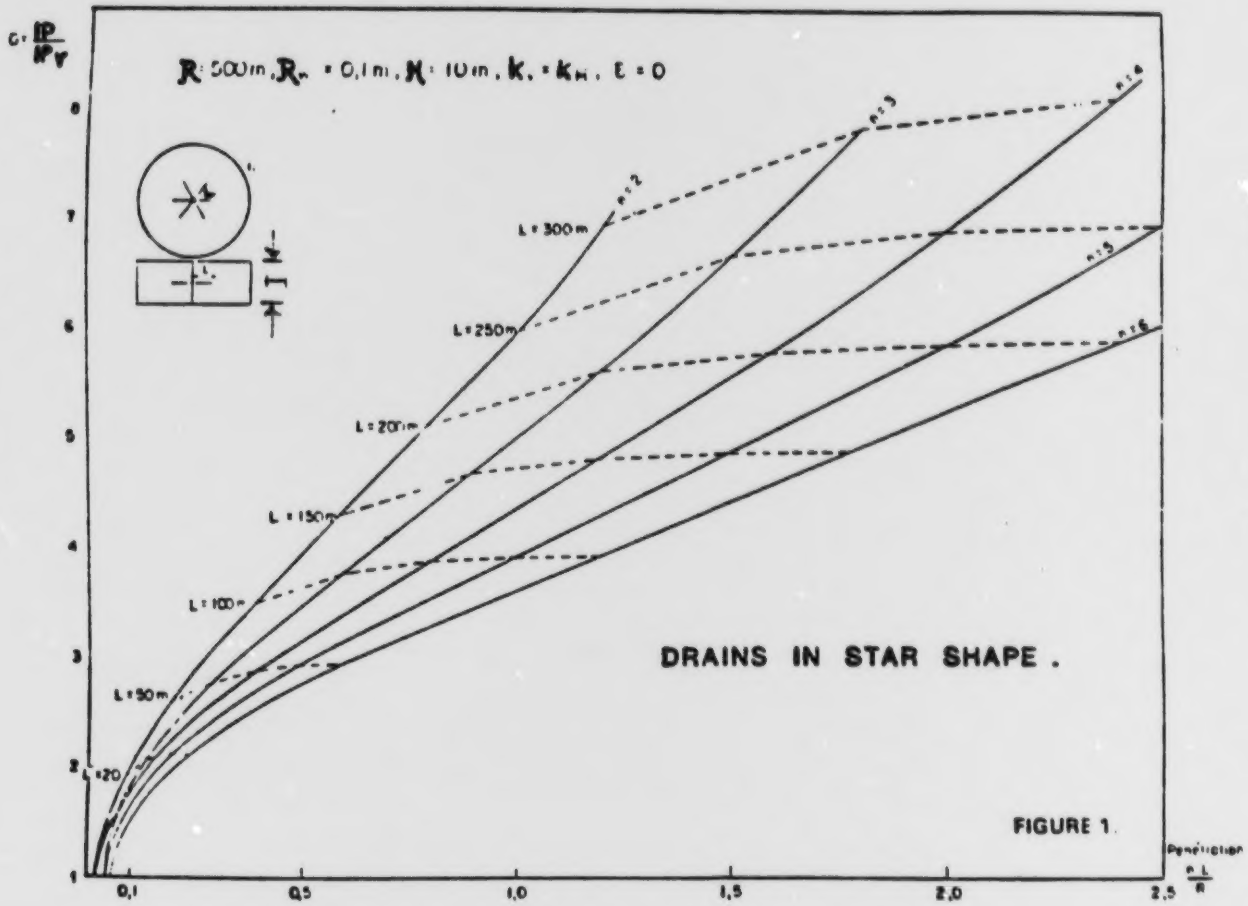

FIGURE 1

INFLUENCE OF THE NUMBER OF BRANCHES .

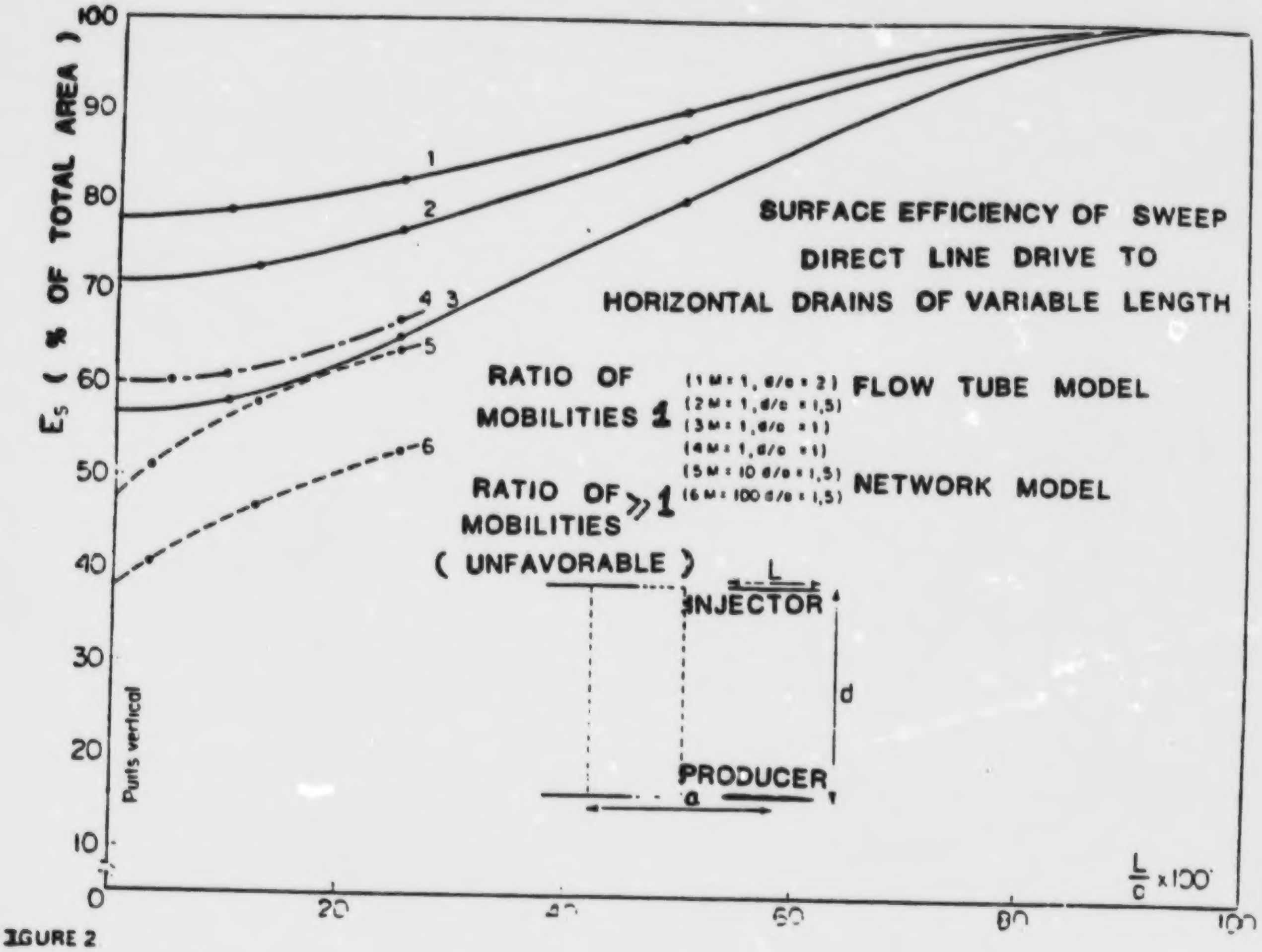

FIGURE 2

IMPROVEMENT OF RECOVERY RATE
DISPLACEMENT OF OIL BY WATER

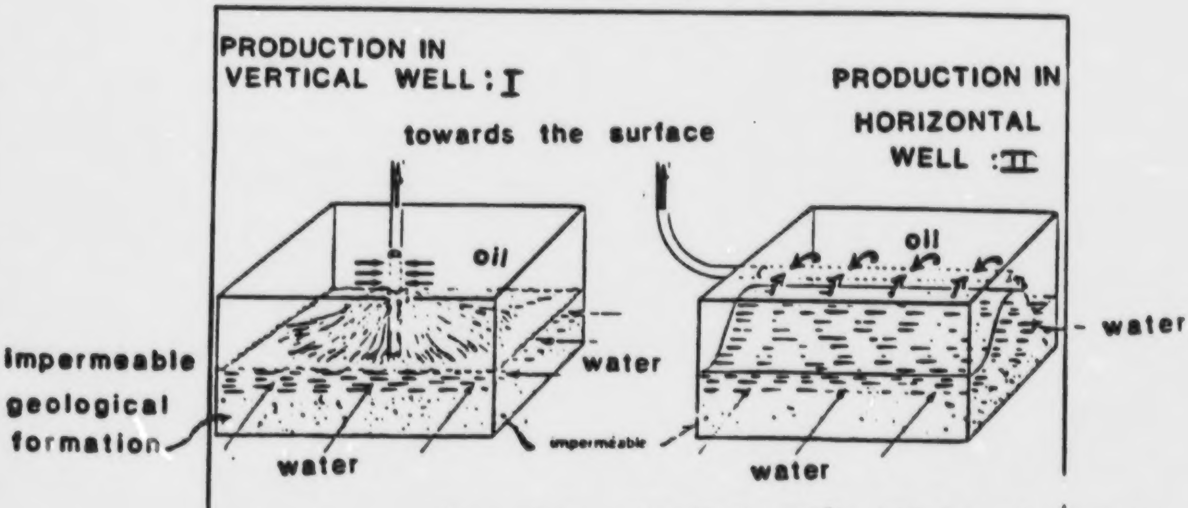
PRODUCTION IN VERTICAL WELL : I
towards the surface
oil
water
impermeable geological formation
water
impermeable
PRODUCTION IN HORIZONTAL WELL : II
oil
water
water

FIGURE 3 the volume of cylinder II > volume of cone I

displacement of oil by water in case II > in case I

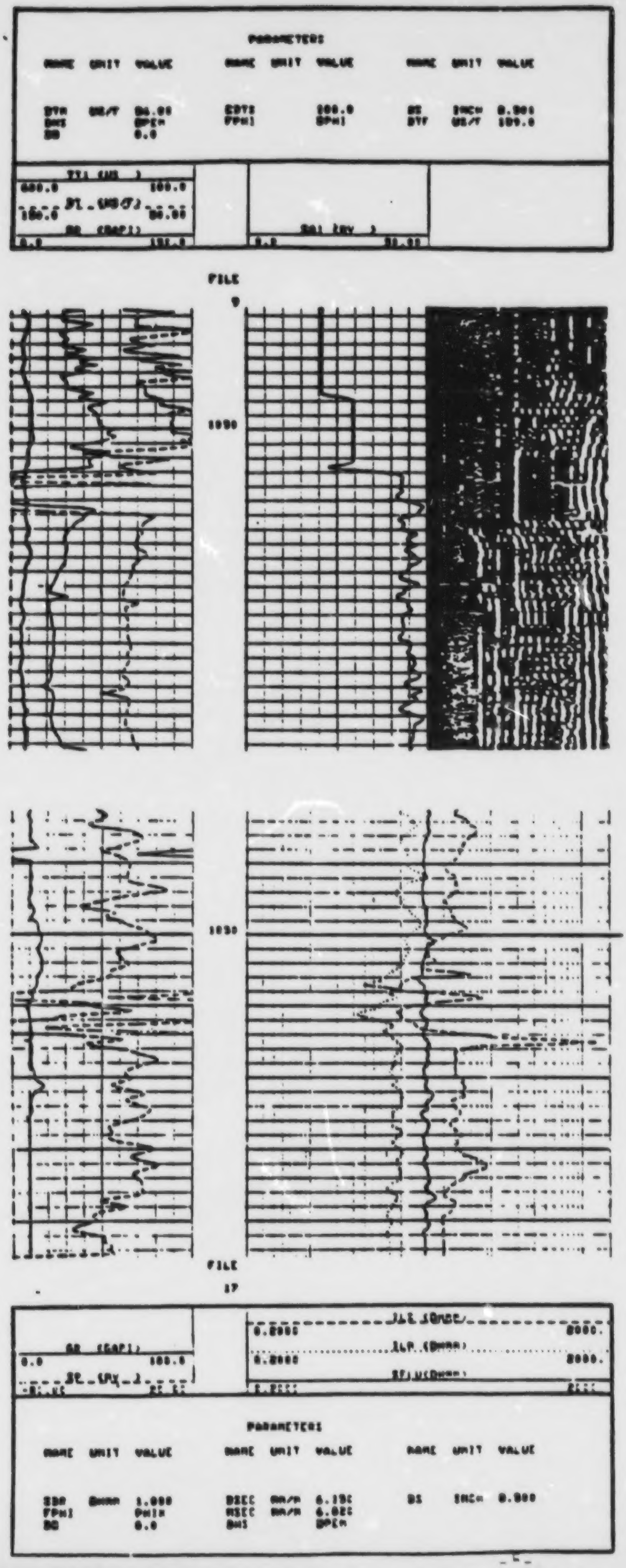

FIGURE 4: "The fractured area located between 1,051 and 1,056 meters appears clearly on these well logs of good quality. On the VDL, upper part on the right, the dark area indicates strong attenuation of the signal. On the representation of the transit times, upper left side, the disconnections indicates characteristic cycle jumps. The induction measurements on the lower right side also reveal important variations. For the interpretation, it has been necessary to go down the signal intensity curve, on the upper right side, of 3.5 m and to go up the gamma ray curve, on the lower left side, of 1.6 m in order to replace them in depths".

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A NEW LOGGING METHOD FOR HORIZONTAL WELLS: "SIMPHOR"(R)

Guy BARON
Christian WITTRISCH
IFP

In what is called the "pump-down" technique, which has been used to date to conduct logs in deviated and highly deviated wells, the logging tool, connected to a 7-conductor electrical cable, is pumped out the open-ended drill string in much the same way a pea is blown out a peashooter. If the open hole to be logged is long, however, then the sonde and cable must be run in and out before and after each extraction of a stand of pipe (27 or 18 m). This rather laborious system requires numerous round trips of the sonde and cable when the logs to be made involve distances or intervals of several hundred meters, as is the case for horizontal drainholes.

In the Lacq 91 well, for example, the length of the drainhole in the pay zone section was 435 meters. Using the pump-down method to conduct logging operations would have required a considerable amount of time; in addition, fifteen trips with 27-m stands of drill pipe would have been necessary to run the cable and sonde in and out. This technique would therefore have involved excessive amounts of time and money.

In order to avoid these problems, a new logging system--the "SIMPHOR" method (Système d'Instrumentation et de Mesures en Puits Horizontaux[1])--was designed, and tested for the first time in the Lacq 91 well.

Basic Principles of the System

The logging tool is mechanically attached to the first joint of the drill string, and connected to the surface by an electrical transmission cable that is located inside the string from the first joint to a side-entry sub, and then outside the string from the sub to the surface.

The logging tool operates as the drill string is tripped in or out of the hole, so that measurements can be recorded at the surface as a function of the length drilled.

---

[1] Translator's Note: Approximate English equivalent: Instrumentation and Measurement System for use in Horizontal Wells

The SIMPHOR system is composed of the following:

--the connector housing, which contains the male plug and links the end of the drill string to the logging tool;

--the logging tool and its protective housing (protector);

--the side-entry sub that takes the cable from inside to outside the drill string, in the vertical or slightly inclined section of the well.

How the System Operates

The logging tools are attached to the inside of a specially designed protector (5-in. tube of glass-fiber reinforced epoxy resin), which is screwed into the drill string. The upper end of the protector is equipped with a 7-conductor male plug. Next, stands of drill pipe are added until the desired depth is reached, say 162 m from total depth (TD).* At the surface a sinker bar, its lower end equipped with a 7-conductor female plug, is positioned and suspended in the last joint of drill pipe. The logging cable is then passed through the window of the side-entry sub and connected to the top of the sinker bar. The side-entry sub--very similar in design to that used with the Azintac steering tool in carrying out directional surveys during drilling--is then screwed to the last joint of pipe.

The sinker bar, now connected to the electrical cable, is pumped with mud down the drill string to the bottom of the hole, while the cable is paid out inside the stuffing box (in the open position) fitted into the side-entry sub window. Once the two plugs are connected at the bottom, the flow of current can be observed at the surface; at the same time, a mechanical anchoring system locks the two parts of the connector so as to prevent any subsequent uncontrolled disconnection of the plugs. The latter are designed so that a residual film of drilling mud cannot interfere with the circuit established when connection is made.

In this example, 162 m of pipe (6 stands) are then added above the cable side-entry sub, and the log is recorded on the trip down. Once the sub reaches a depth of 162 m below the rotary table, the same log can be recorded on the up trip, as a double check.

By means of this procedure, which was repeated three times using a combination Dual Induction-Gamma Ray tool, the following segments in the Lacq 91 well were surveyed:

--1st segment: '770 m to 916 m, i.e. 146 m on the down trip,
'925 m to 790 m, i.e. 135 m on the up trip;

--2nd segment: '918 m to 1061 m, i.e. 143 m on both the up and down trip;

--3rd segment: '1085 m to 1227 m, i.e. 142 m on the down trip,
'1235 m to 1076 m, i.e. 141 m on the up trip.

As the above example shows, there is a distinct advantage to having the runs overlap each other slightly rather than making them contiguous, as this facilitates subsequent alignment of the logs recorded.

---

* 162 m representing a good third of the total length (435 m) logged in the Lacq 91 well.

It was decided to conduct the logs in three runs at Lacq 91 in order to avoid damage to the electrical cable in the annulus between the 5-in. drill pipe and the 9 5/8-in. casing, especially at the point where the cable exited from the side-entry sub. At 162 m below the rotary table, the sub was tipped only 9° in the casing, the KOP being located at -85 m. To perform the same logging operation in two runs instead of three would have meant lowering the side-entry sub to a depth of 250 m below the table, and tipping it in the casing at approximately 22°. As this was the first time the SIMPHOR system had been tested, it was decided not to take such a risk.

The kickoff point for the Rospo Mare RSM6D horizontal well (the third well of the FORHOR project) was -520 m. Even if it had been possible to run in the side-entry sub to that depth in perfect safety, it would have been impossible to conduct the logs in a single run, as the total length of the drainhole to be logged was 603 m.

The operations were therefore conducted in two runs, under the following conditions:

I. RSM6D: logs in the 8 1/2-in. open hole.

a) Bore Hole Geometrical Tool (BGT) and Gamma-Ray (GR):

1st segment: from 2310 m (at an angle of 90°) to 1820 m (82°), i.e. 490 m;
2nd segment: from 1900 m (84°) to 1670 m (78°), i.e. 230 m.

b) Induction (ISF), Sonic (BHC), and Gamma-Ray (GR):

1st segment: from 2308 m (90°) to 1834 m (82°), i.e. 474 m;
2nd segment: from 1945 m (89°) to 1625 m (79°), i.e. 320 m.

c) Dual Laterolog (DLL) and Gamma-Ray (GR):

1st segment: from 1575 m (79°) to 2049 m (96°) on the down trip, i.e. 474 m;
from 2058 m (96°) to 1630 m (79°) on the up trip, i.e. 428 m.
2nd segment: from 1975 m (90°) to 2295 m (90°) on the down trip, i.e. 320 m;
from 2305 m (91°) to 1975 m (90°) on the up trip, i.e. 330 m.

The Gamma-Ray log provides a common basis for identifying the position of each segment, and, together with the overlaps, makes it possible to constitute a complete log of the horizontal hole. The quality of the log was demonstrated by comparing the recordings obtained for each run up and down.

With a view to demonstrating the advantages and possible disadvantages of the SIMPHOR method, a Neutron Density-Gamma Ray log was also conducted, using another procedure and special equipment provided by Schlumberger.

II. RSM6D: logs in the 9 5/8-in. cased hole.
It should also be noted that, in order to check the quality of the cementing

job on the 9 5/8-in. casing, the shoe of which was set at an angle of 79°, a CBL-GR log was conducted in the cased hole using the SIMPHOR method.

Future Prospects

At Lacq 91, logs were conducted in three runs and explored 435 m of horizontal drainhole.

At Rospo Mare RSM6D, two runs and corresponding operations sufficed to explore 603 m.

It would therefore seem obvious that the number of runs (one, two, or three) depends on the depth of the horizontal well's initial kickoff point (KOP). For wells with a deep KOP in particular, it should be possible to conduct future logging operations in a single run, using two protection tubes set end to end so as to protect a combination of three or four sondes. The advantages to be derived from the SIMPHOR system would then be as follows:

- --possible use of large-diameter sondes, which perform better than small-diameter logging tools;
- --possibility of circulating the drilling fluid through the drill string to the bottom while the log is being recorded;
- --increased safety in perforating horizontal wells with 4-in. guns, as the electrical connection is no longer made at the surface, but at the bottom of the hole;
- --reduced number of round trips as compared with the pump-down technique;
- --reduction in time spent, operating costs, etc.

The FORHOR project is currently studying the possiblity of using the SIMPHOR method for conducting production logs in horizontal wells.

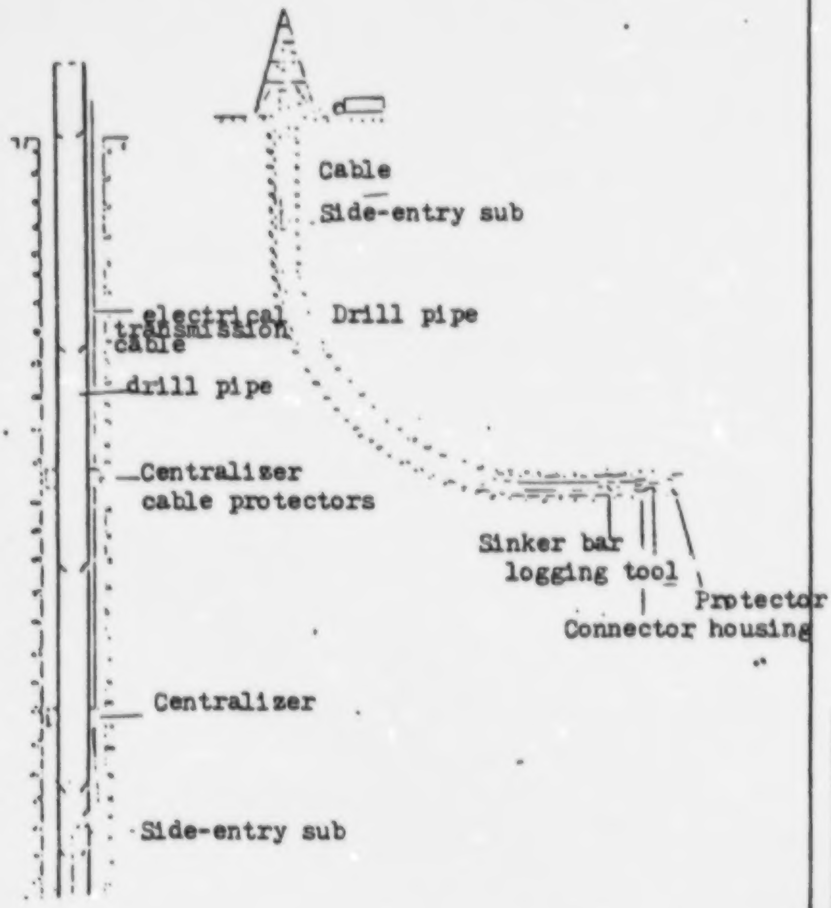
The authors of the preceding articles would like to add the following comments:

First, although it is true that horizontal drilling is not recommended in every case, it is manifestly superior to other methods in reservoirs such as those containing tight gas.

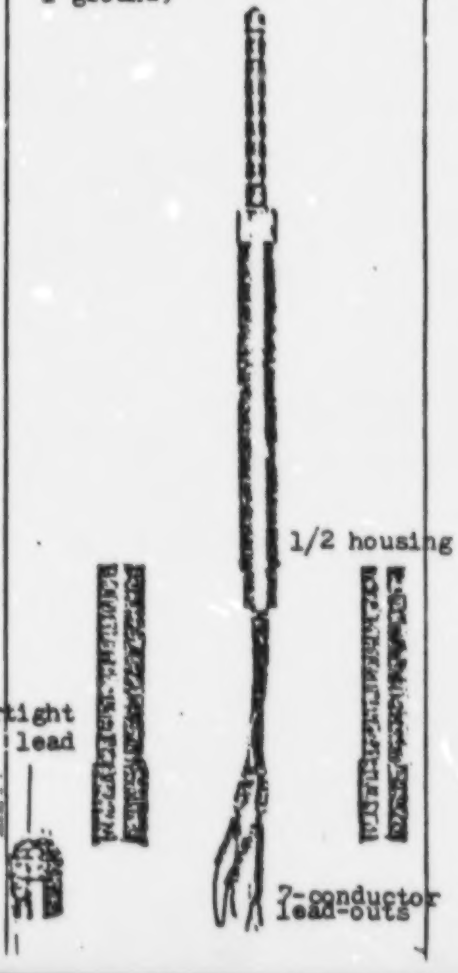
Second, it should be kept in mind that FORHOR is a scientific research project that has not yet been completed, and although drilling and measurement problems have thus far been solved in a satisfactory manner, the major step that remains to be taken is selective completion, which is the main goal of the project.

Finally, the authors wish to express their thanks to the management of the IFP and SNEA(P) for permission to publish these data; they naturally also wish to thank their many colleagues who contributed so much to the effectiveness of this team project.

Basic Principles of the Simphor System


Cable
Side-entry sub
electrical transmission cable
Drill pipe
drill pipe
Centralizer cable protectors
Sinker bar
logging tool
Protector
Connector housing
Centralizer
Side-entry sub

Bottomhole Connector
male plug 8 contacts (7+ 1 ground)


1/2 housing
watertight lead
7-conductor lead-outs

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HORIZONTAL WELL EQUIPMENT

François GIGER
IFP

Need for Specialized Techniques in Equipping Horizontal Wells

In the technical literature the Soviets, who were the first to record the drilling of significantly long horizontal wells, blamed the fact that horizontal drilling is a seldom-used technique on a lack of expertise in equipping the section of horizontal hole lying within the producing zone. We believe it is vital that the petroleum industry search for satisfactory solutions to this problem. The zone to be produced, which today may exceed 500 m in length, generally contains various facies which contribute to the heterogeneous nature of the reservoir, as well as fissures which may sometimes constitute the desired target (formation logs conducted in the Lacq 91 and Rospo Mare 6 wells confirm this analysis). It is therefore necessary to be able to set up a selective production system that can be adapted to each particular case.

Contrary to what would have been preferable, the first equipment run into the horizontal section of three FORHOR-project wells was a perforated liner. The drillers considered it the easiest equipment to run in that was capable of guaranteeing the geometric integrity of the structure by preventing obstruction in the event of a cave in. After production began, however, these liners proved a considerable handicap with respect to the two opposing problems that characterized the Lacq field: low productivity in the case of LA 90, and high productivity, with considerable water production from an aquifer-fed fracture, in the case of LA 91.

Following is a description of the different workover operations conducted at the above sites: stimulation by acidizing at LA 90, and fracture plugging at LA 91, which was then partially brought in.

Stimulation of the LA 90 Well

The problem consisted in forcing acid into the formation through the well walls and distributing it as evenly as possible within the producing zone. The pitfall to be avoided was creating a preferential channel that would then take up most of the acid used in the treatment.

The method employed is as follows:

A) (Figure 1)--A slug of acid was circulated through the production string to the bottom of the well. The annulus remained open at the wellhead.

B) (Figure 2)--In order to position the end of the production string near the boundary between the acid and the well mud, the string was withdrawn 80 m.

C) (Figure 3)--The annulus was closed at the wellhead and a small slug of water injected, followed by a slug of gel and another small slug of water. The total volume of water and gel equalled that of the acid. The goal of this step of the operation was to forcibly inject the acid through the walls at the bottom of the well; inside the well, the acid was replaced by a volume of fluid sufficiently viscous to prevent backflow later on in the operation. The gel used had a guar base.

D) (Figure 4)--Steps A, B, and C were carried out again a number of times, so that the entire producing zone could be treated. Each time the procedure was repeated, the boundary between the mud and the gel that had just been injected was taken as the bottom of the well.

The entire operation was conducted in one day. The productivity index was increased from 2.67 m^3/day/bbl to 6.55 m^3/day/bbl or by a factor of approximately 2.5. However, because of the reservoir geology and the fact that blobs of oil were distributed in a flooded zone, oil production was actually increased only 25%.

Fracture Plugging and Cementing in the LA 91 Well

During drilling at LA 91, complete losses of circulation were experienced beyond a depth of 1050 m; the logs conducted revealed a large fracture at this spot. The influence of the fracture was felt when the well was brought in, as the water cut exceeded 99%. (By way of comparison, the best of the neighboring wells had an oil cut of about only 4%.) A workover operation was begun in order to plug the fracture and attempt to selectively bring in a horizontal well for the first time.

A) (Figure 1)--The slotted liner was fished out. It would have been impossible to work through this liner, as a considerable number of slots were plugged by mud deposits.

B) (Figure 2)--The hole was monitored. The well was shown to have remained open to the bottom, the section of which was larger than that of the bits.

C) (Figure 3)--A water injectivity test and temperature survey were carried out. In order to determine to what extent the fracture remained open and stable, water colder than the reservoir was injected, and the drop in temperature noted where the water had circulated. The measured injectivity index was 240 m^3/day/bbl.

D) (Figure 4)--The bottom of the well was protected with gel. So as to avoid plugging the bottom of the well with cement during the next step, a guar-based gel was pumped into the hole to a point below the fracture.

E) (Figure 5)--The fracture was plugged. Two tonnes of sand were forced into the fracture, and a cement slurry then injected through the mass of sand.

F) (Figure 6)--The hole was monitored once more. The cement injected into the fracture was shown to have spread out into the well a distance of only 10 m on either side of the fracture.

G) (Figure 7)--A second water injectivity test and temperature survey were carried out. The injectivity index measured was 6 m^3/day/bbl, i.e. 40 times lower than it had been before the fracture was plugged. Analysis of the temperature survey revealed that water was no longer flowing into the fracture. It was entering the reservoir only at spots where a permeable matrix had previously been identified by logs, as should have been the case.

M [sic] (Figure 8)--A composite liner was run in. Taking its shoe as a starting point, the liner comprised a section of slotted tubing, an external packer, a section of solid tubing, a second packer, a ring of cement with anti-return valves, and a second section of solid tubing.

The purpose of the perforated tubing was to ensure production in the well bottom. The first section of solid tubing, located between the two packers, was designed to reinforce the seal obtained by plugging the fracture. The second section of solid tubing was to be cemented and perforated so the corresponding producing zone could be brought in.

K [sic] (Figure 9)--An attempt was made to expand the packers. However, none of the cement-injection operations to expand the rubber sheath of the packers succeeded in producing a seal between the liner and the well wall.

L [sic] (Figure 10)--The liner was perforated at a depth of 1085 m. As the packers had not worked as planned, it was decided to cement the liner around the first section of solid tubing as well. To allow the cement to pass out of the liner, a perforating operation was attempted with a string of guns pumped through a hollow tube to a depth of 1085 m. The operation was successful.

M) [sic] (Figure 11)--The liner was cemented in a single operation, using a thixotropic cement.

N) [sic] (Figure 12)--A leak-off test was performed, and revealed a good seal at the head of the liner for the cement located in the annulus between the liner and the 9 5/8-in. casing.

P) [sic] (Figure 13)--A cement bond log was conducted, using the SIMPHOR system. The log revealed watertight bridges of cement distributed from place to place.

The well was left in this state and brought in so that the bottom zone could be evaluated. The latter produced more than 30 m^3/day of oil and water. The oil cut exceeded 10%, more than double that of neighboring wells.

The entire operation was completed in six weeks. This rather considerable length of time may be explained by the fact that, while the operation was being carried out, solutions to entirely new problems had to be found and numerous incidents dealt with.

Another operation, which has just been completed, made it possible to bring in the zone located opposite the second section of solid tubing, after the cemented liner had been perforated. Simultaneous, independent production from the two zones will be guaranteed by two pumps.

Conclusion

Equipping and stimulating a horizontal section of well in a reservoir poses new problems for the petroleum industry. The partial success in this area realized to date during the workovers carried out on the LA 90 and LA 91 wells enables us to make the following statements:

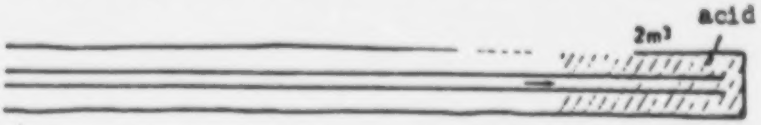
--stimulating and cementing horizontal wells is possible, but the quality of such operations must be improved;

--installing packers involves special problems; by modifying the design of such packers we hope to solve these problesm.

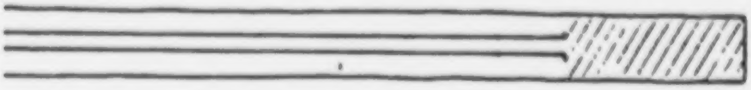
The impressive array of techniques that may be proposed will best be put to use by dealing with the specific problems appearing at each new site one by one.

ACIDIZING THE LACQ 90 WELL

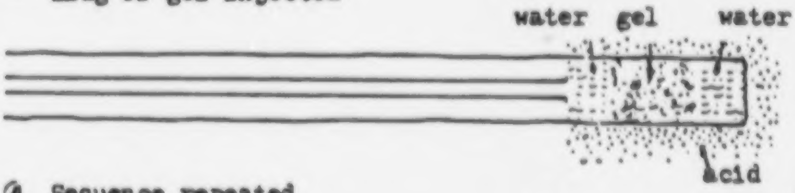
① 1st slug of acid circulated to well bottom



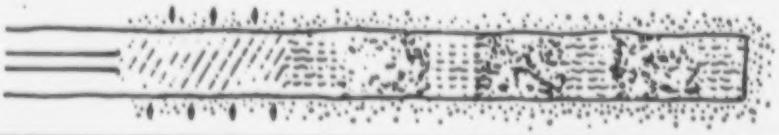
② Production string withdrawn 80 m



③ Slug of gel injected


water
gel
water
acid

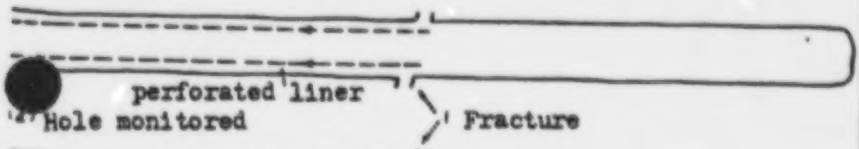
④. Sequence repeated



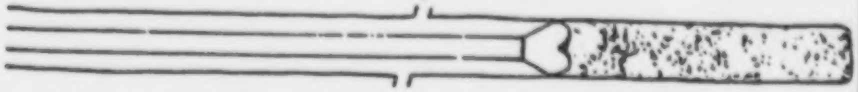
Figures 1 to 4

LACQ 91: 1st WORKOVER OPERATION

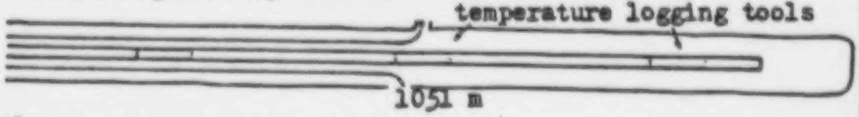
(1 Slotted liner fished out


perforated liner
Fracture

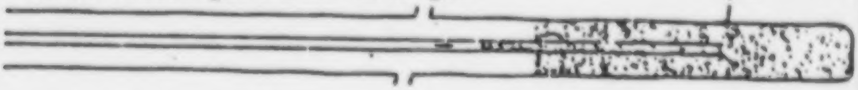
(2) Hole monitored



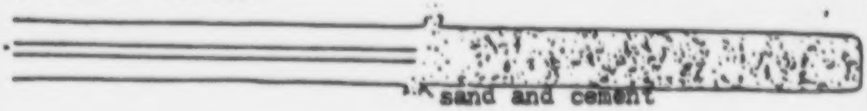
(3 Water injectivity test and temperature survey


temperature logging tools
1051 m

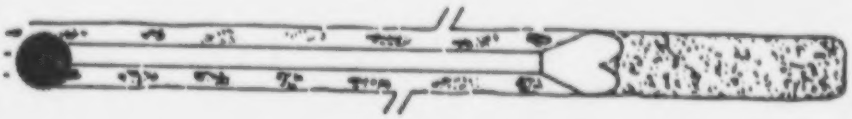
(4 Well bottom protected with gel



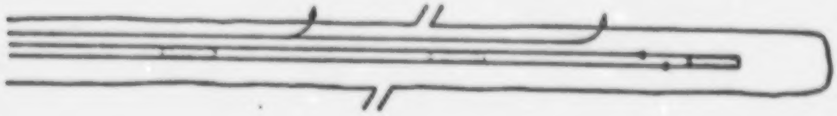
(5)Fracture plugged


sand and cement

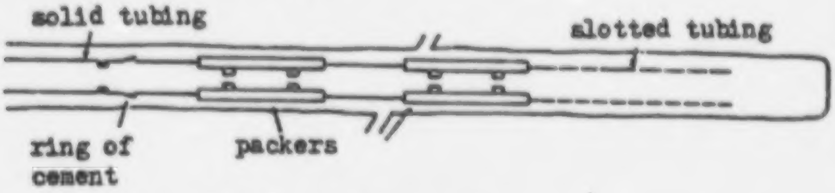
6) Hole monitored



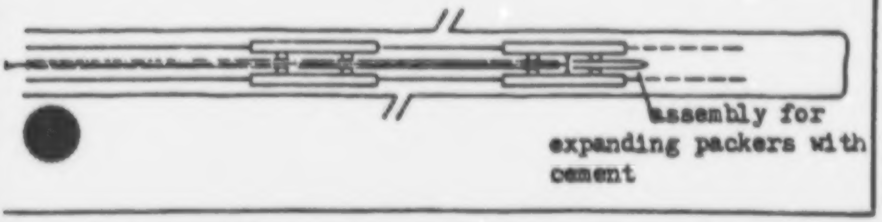
7 Water injectivity test and temperature survey



8) Composite liner run in


solid tubing
slotted tubing
ring of cement
packers

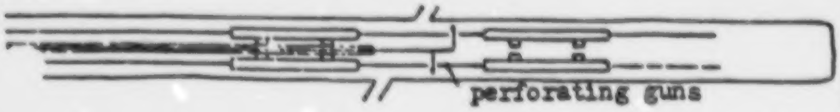
(9. Expansion of packers attempted


assembly for expanding packers with cement

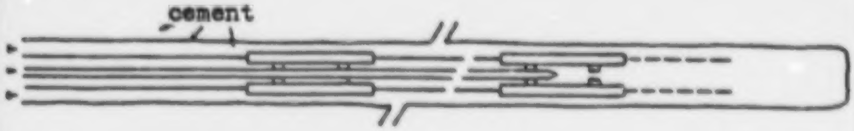
FIGURES 1 to 9

LACQ 91: 1st WORKOVER OPERATION

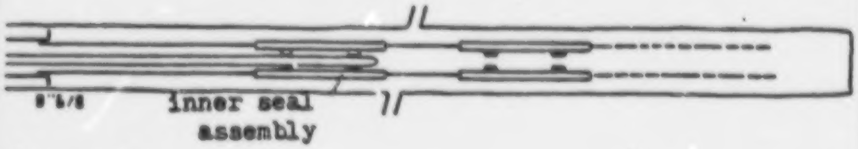
10 Liner perforated at 1085 m


perforating guns

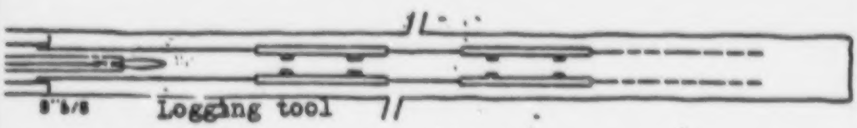
11 Liner cemented



2 Leak-off test


9"5/8
inner seal assembly

3 Cement bond log


9"5/8
Logging tool

SINPHOR equipment

IGURES 10 to 13

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(15)

Horizontal drilling methods proven in three test wells

Marc Dorel, Director of Drilling and Completion, Institut Francais du Pétrole (IFP), Paris, France

10-second summary

The practice of drilling horizontally through a reservoir by deviating the wellbore 90° from vertical requires precise planning and sound engineering practices. This article takes a look at the operational, engineering and planning aspects of three successfully drilled drainholes. It also presents a field-tested horizontal well logging procedure that may help extend and improve this technology.

THE DRILLING OF HORIZONTAL or near-horizontal holes to increase the amount of reservoir that will be drainable by the wellbore is not a new idea. But until recently, very few wells of this type have been drilled in Western countries since there was little incentive to spend additional money on the technique when most reservoirs could be produced more economically by conventional methods.

In the last few years, the situation has changed. Conditions now favor new methods of enhancing oil recovery from existing reservoirs, as well as producing hydrocarbons from new types of reservoirs only marginal by conventional methods. Experience in highly deviated wells and associated technology improvements have increased the feasibility of extending hole angles to 90° so that horizontal drilling can be considered.

As part of an intensive research program partially supported by French and European public authorities, the French association IFP (Institut Français du Pétrole) and Elf-Aquitaine (as operator) have recently drilled, logged and completed three horizontal wells in Western Europe. Two onshore wells were drilled in France (Lacq 90 and Lacq 91), and one offshore well has been drilled in the Italian Adriatic Sea (Rospo Mare 6D).

Following are details on how these wells were planned and drilled. Also included is the description of a new technique for getting logging tools to bottom in these highly deviated wells.

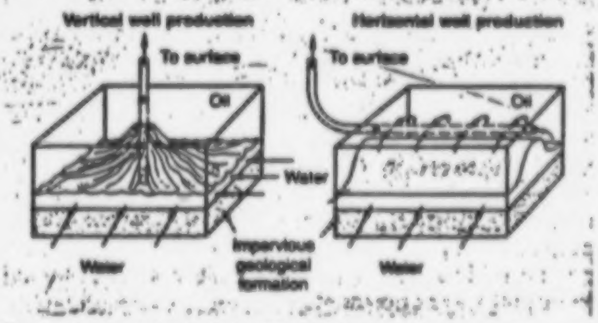

Fig. 1—Horizontal drain hole drilling produces a significantly improved recovery ratio by increasing the cylindrical volume exposed to the formation. Also the coning effect of underlying water is less.

PRELIMINARY STUDIES

The project was launched in early 1979 and began with engineering studies to demonstrate the effectiveness of a horizontal hole in an area where hydrocarbon recovery is poor or unsatisfactory. Analytical derivations and numerical reservoir simulations confirmed that the following advantages could be expected in specific areas:

- Five times greater productivity due to the borehole's configuration within the reservoir
- Increased ultimate recovery resulting from a reduction in water or gas coning (Fig. 1)
- Possible intersection and linking of vertical fractures in tight reservoirs
- Possible use for enhanced recovery methods and steam injection.

Prior to drilling the Lacq 90 and 91, a comprehensive investigation was made of near-horizontal and horizontal drilling operations currently in use. Experienced operators and contractors were interviewed regarding equipment, techniques and limiting conditions for high-angle drilling operations. Then, during the preliminary engineering phase, these drilling problems were listed and their solutions analyzed. Torsional and axial frictional drag was one such problem that made any movement in the hole difficult and reduced the capability of controlling weight on bit and, therefore, hole direction. Difficulties in cleaning the hole as well as an increased tendency for differential

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TABLE 1—Time analysis for Lacq 90 well

Operation	Time hrs.	Percent
Drilling and coring	237	23
Reaming and tripping	432	42
Casing and BOP installation	119	12
Deviation surveys	126	12
Downtime-repairs	114	11
Total	1,028	100

sticking were also problems. Additionally, new procedures were needed for logging and completion. Finally, formation stability when drilling a 90° hole was an unknown factor.

Although no specific solutions were found to solve these problems beforehand, it was concluded that they posed no major obstacle that would prevent starting a test well. The Elf-owned Lacq oil field in southwest France was selected as a test site, since the reservoir is shallow (2,200 ft) and partially flushed.

LACQ 90 DRILLING PROGRAM

This well was drilled mainly to confirm feasibility studies and objectives were limited. The drilling program was relatively simple and consisted of standard hole sizes (17½-in., 12¼-in. and 8½-in.). Casing strings included 13⅜-in., (set at 1,084 ft) to cover unconsolidated formations, and 9⅝-in., set just above the reservoir. Production pipe was to be a 7-in. slotted liner and was not cemented.

Directional surveys would be made with conventional single-shot instruments and a wireline steering tool. Additionally, the drilling program called for a buildup rate of 1° per 30 ft (or more if practicable) and, if necessary, use of an oil-based mud to minimize torque and drag in the 8½-in. hole.

Drilling operations. The well was drilled in 44 days (See Table 1 for time analysis). Horizontal displacement was 2,191 ft with a total vertical depth of 2,198 ft (Fig. 2). To accomplish this, it was necessary to drill 3,563 ft of measured hole, 886 ft of which were cut within the reservoir. Some 328 ft were drilled at angles between 89° and 92°.

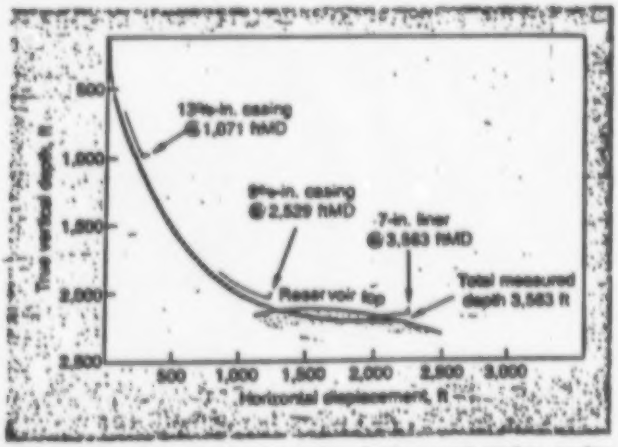

Fig. 2—This diagram shows relative displacement angles, casing points and reservoir position for the Lacq 90 well, drilled in France. Well depths are shown as measured depths.

The 17½-in. hole started below conductor pipe and was drilled to 1,076 ft using downhole motors. Kick-off point was located at 289 ft utilizing a 2½° bent sub that yielded a 28° angle at casing depth. The 13⅜-in. casing was then run and cemented.

After waiting on cement, a 12¼-in. hole was drilled to 2,536 ft. Conventional rotary drilling and a limber string were used continuously except between 1,608 ft and 1,772 ft, where directional drilling was used to build hole angle, which reached 70° by 2,530 ft, where 9⅝-in. casing was set and cemented.

Drilling continued using a downhole motor with a 1½° bent sub, and 8½-in. hole was drilled to a depth of 3,202 ft, where inclination reached 89°. At this point, the bent sub was retrieved and the well was turbodrilled to its final measured depth of 3,563 ft (about 2,192 ft TVD). Three cores were cut during this interval, and a gamma ray log was run to TD through the drill pipe. Following this, a 7-in. slotted liner was set but not cemented.

Drill string assembly. While drilling 17½-in. hole, 7¾-in. drill collars and 5-in. heavy-weight drill pipe were run above the bent sub and non-magnetic collar. During reaming operations, the drill string was rotated conventionally. It included one near-bit stabilizer and another stabilizer one joint above. Buildup rate was intentionally increased to an average of 1° to 4° per 30 ft. The same type of assembly was used while drilling 12¼-in. hole.

In 8½-in. hole, the string generally consisted of one near-bit stabilizer, two or three non-magnetic collars, two 6½-in. drill collars, with 5-in. heavy-weight drill pipe above. When inclination reached approximately 85°, drill collars were removed, leaving only the non-magnetic collars and heavy-weight pipe. One jar was then added to the string.

Coring was done with a short core barrel rotated by the downhole motor. While reaming the hole, the drill string was rotary-driven. At a depth of 3,202 ft, the 1½° bent sub was laid down.

Directional surveys. When directional surveys were required, they were conducted using either a steering tool or single shot. Over the course of the well, a total of 95 measurements were taken, 76 with single shot, and an additional 19 with the steering tool. This tool was used only while turbodrilling since it was connected to surface by wireline. Single shot surveys were pumped down the drill pipe when the inclination exceeded 75°. At the end of drilling, gyro and multishot measurements were made from the 9⅝-in. casing shoe to surface.

Drilling fluid. Aside from the primary function of cleaning the hole, the drilling mud on a high-angle hole must reduce torque and drag. Therefore, provisions were made to use an oil-base mud after setting 9⅝-in. casing. A freshwater gel mud was first used to drill to 2,133 ft, at which point 10% diesel oil was added in preparation for running 9⅝-in. casing. Mud viscosity of 60 sec/qt was required to clean the hole.

After drilling out, it became apparent that because of the demonstrated ability of the freshwater mud, that there was no need for an oil-base mud. A decision was made to simply increase the percentage of diesel oil in the mud to 20%, while maintaining an average viscosity of 60 sec/qt and a weight of 8.9 ppg. Proper solids control helped keep drill solids below 5% by volume. No problems during tripping or connections were encountered, and all three casing strings were run without difficulty.

LACQ 91 DRILLING PROGRAM

Elf and IFP designed the drilling program for this well by applying the experience gained in drilling Lacq 90—hole sizes, casing program and buildup angles were the same. The only significant program change was the angle at the 9⅝-in. casing shoe, which was increased to an optimum value of 80°.

In addition to confirming previous success, new goals were set for this second experimental well. These included increasing total length of the horizontal portion of hole, carrying out a well-logging program in open hole and possibly cementing the production string.

Drilling operations. The second well was drilled in 42 days, and reached a measured TD of 4,100 ft. It penetrated the reservoir for over 1,542 ft, of which 1,214 ft were nearly horizontal (See Fig. 3).

The well was drilled problem-free until reaching the second kick-off point in 12¼-in. hole. There, close to the top of the reservoir, loss of buildup rate between 2,179 ft and 2,402 ft prevented operators from reaching the 80° angle as projected. Only 67° was achieved at the 9⅝-in. casing shoe depth.

At this point, Elf and IFP were concerned that the target would be missed if buildup did not reach 90° within a short vertical distance of say, 80 to 100 ft, which would require a mean value of 3° per 30 ft buildup rate. This was thought feasible so it was decided to run and cement 9⅝-in. casing, which was done successfully.

After drilling out, the operator tripped into the hole with an 8½-in. bit, using a "cracker" type assembly made of a 4¾-in. K-Monel collar above an 8½-in. near-bit stabilizer. This rotary-driven assembly proved to be excellent and yielded 89° of inclination at a measured depth of 2,914 ft. The average rate of buildup of 2.9° per 30 ft was achieved and the target was reached. After reaming this portion of hole, a three-point stabilized assembly was used to drill to 2,982 ft (MD) with an inclination of 91°.

Coring and drilling were conducted in the horizontal hole from 2,982 to 3,448 ft (MD), using a downhole motor. Three cores, each nearly 30 ft long, were cut for reservoir studies, and each had a high recovery rate. Two more cores were cut, each having a length of 13 ft and a 100% recovery rate, between 3,645 to 3,658 ft and 3,803 to 3,816 ft. Turbodrilling then continued to a measured TD of 4,100 ft.

A lost-circulation problem at 3,448 ft dictated that a cementing job should not be attempted. Therefore, a 7-in. slotted liner with centralizers was run to 4,085 ft without incident.

Directional control and surveys. Particular attention was given by the operators to ensure proper surveys of the Lacq 91. This important and time-consuming operation was conducted by TMP Service, a France-based directional drilling contractor. Engineers selected a Teleco measurement-while-drilling mud-pulse system for monitoring the 17½ and 12¼-in. drilling phases. The tool proved to be efficient and performed up to expectations. Crews also ran magnetic single-shot units and Azintac (a wireline steering tool) to compare azimuth and hole angle to recorded values. No significant discrepancies were noted. Also, more than 50 hours were saved during survey operations compared to the previous Lacq 90 well.

In the 8½-in. horizontal portion of the hole, the MWD tool could not be used due to its 8-in. OD. Therefore, single-shot units and the steering tool were run, and, to save time, surveying stations were reduced to a minimum. Table 2 gives variations of the horizontal drain hole position showing a light dropoff in the well at 3,222 ft (MD) after turbodrilling and turbocoring operations. A cracker assembly (4¾-in. K-Monel drill collar) was used to build angle back to more than 90°. The same dropping effect appeared at 3,773 ft (MD) following coring operations, although the azimuth remained constant in this portion of the hole. Besides the choice of bottomhole assemblies and drilling parameters in highly deviated holes, rotary speed also proved to be important. And, the tendency of the drill string to drop off had to be counteracted by select-

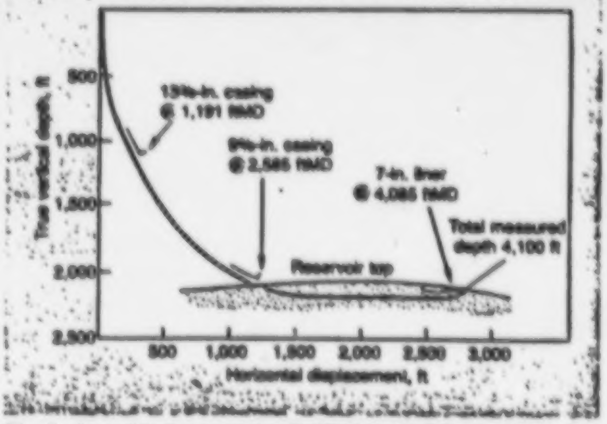

Fig. 3—Lacq 91, the second well drilled in the Elf-owned field, has longer reservoir penetration at a greater depth.

TABLE 2—LACQ 91 directional measurements in 8½-in. drain hole portion

Measured depth, ft	Inclination angle	Magnetic azimuth	Vertical depth, ft	Horizontal displacement, ft
2,948	90.1°	S56.5°W	2,181.2	1,563.8
2,979	90.6°	S56.7°W	2,181.0	1,593.0
3,130	89.25°	S58°W	2,181.2	1,748.8
3,222	87.75°	S58°W	2,183.6	1,836.3
3,310	87.5°	S58°W	2,187.6	1,926.5
3,370	85.5°	S58°W	2,191.5	1,985.2
3,484	85.5°	Inclinometer	2,200.5	2,099.2
3,514	87.0°	Inclinometer	2,202.5	2,129.6
3,547	88.5°	S57.5°W	2,204.1	2,161.3
3,648	93.0°	Inclinometer	2,202.8	2,262.7
3,760	92.5°	Inclinometer	2,197.4	2,373.8
3,849	91.25°	Inclinometer	2,194.5	2,462.1
4,032	87.0°	Inclinometer	2,197.5	2,645.2

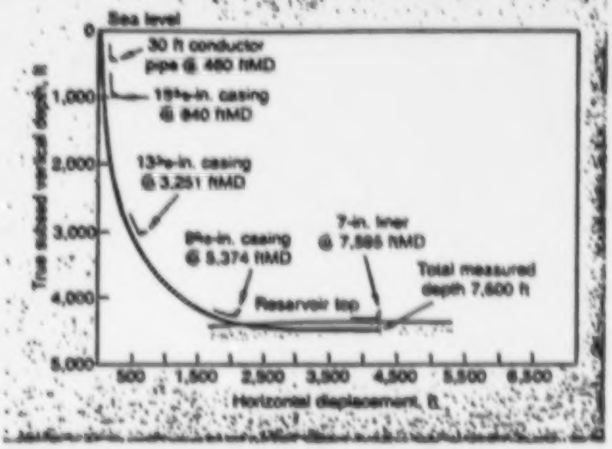

Fig. 4—Rospo Mare 6D, drilled offshore in the Italian Adriatic Sea, exhibits good directional control and approximately 2,000 ft of reservoir penetration.

ing the best sizes, types and position of drillstring stabilizers.

Logging procedure. The horizontal drain hole portion of Lacq 91, in which the length of the pay zone is about 1,427 ft, did not lend itself to common logging procedures, as they tend to be excessively time-consuming. Consequently, a new logging method was conceived and tested. It will be discussed in detail later in this article.

ROSPO MARE DRILLING PROGRAM

Following the successful operations conducted at shallow depths on Lacq 90 and 91, it was decided to test a similar program for reaching deeper and more extended objectives. The vuggy reservoir containing heavy, viscous oil discovered at Rospo Mare was the ideal target for the project. The test well, Rospo Mare 6D, was spudded during the first quarter of 1982 and had extended operational considerations due to increased vertical depth and drilled length (Fig. 4).

Drilling operations. Drilled offshore from a fixed platform, the well reached a final drilled length of 7,599 ft in 71 days, crossing 1,988 ft of reservoir between 75° and 96°, which included a 1,542-ft section drilled after reaching 90°. The average true vertical depth of the horizontal portion was 4,495 ft.

Both 17½-in. and 12¼-in. holes were drilled with KCl mud to alleviate problems with troublesome shale formations. The 13⅜-in. casing was set at 3,251 ft, whereas the 9⅝-in. casing nearly reached the top of the reservoir at 5,374 ft (MD) and 80° inclination. The only problems encountered were those normally associated with any high angle directional drilling operation.

Maintaining the 8½-in. horizontal hole at its predetermined depth and course was difficult because of the heterogeneity of the reservoir. Many trips were required to modify stabilizer positions, and deviation surveys had to be made more often than scheduled. Although the downhole motor was used intensively, any sharp corrections of inclination were made by rotary drilling.

Upon reaching TD, nine cores were cut and a complete set of electrical logs recorded prior to running 7-in. slotted liner.

Logging operations. The newly devised horizontal well logging system (see following section) was successfully used on this well to record a complete set of logs including: in 9⅝-in. casing, cement bond (CBL)/gamma ray (GR)/casing collar locator (CCL) logs; and in 8½-in. open hole (with the 3⅜-in. size tools); borehole-compensated induction sonic (BHC-ISF)/variable density (VDL)/gamma ray/borehole geometrical tool (BGT)/dual laterolog (DLL). Additionally, a density neutron gamma ray combination tool (1 11/16-in.), moved by pumping down the drill pipe, was also run.

NEW LOGGING PROCEDURE

Pump-down techniques are commonly used for logging highly deviated holes in which conventional gravity-descent tools cannot be used. The logging tool generally is pumped out open-ended drill pipe string to TD. The tool must be run in and out of the drill pipe before and after the stand of drill pipe is retrieved if the open hole section to be logged is long. Therefore, both logging tool and cable are required to make numerous trips to log the entire section of pay zone.

This method is slow and limited and, up to now, included only a few basic log types. Also, when considering in excess of a thousand feet of horizontal hole, one should consider the necessity of obtaining a full range of quality logs, which normally means using conventionally sized tools.

To remedy this situation, a new logging method, known today under the name of Simphor (Systeme d'Instrumentation et de Mesures en Puits Horizontaux), was designed and developed by the Forhor association (see Fig. 5). As discussed previously, this system was used successfully to log Lacq 91 well. Total length

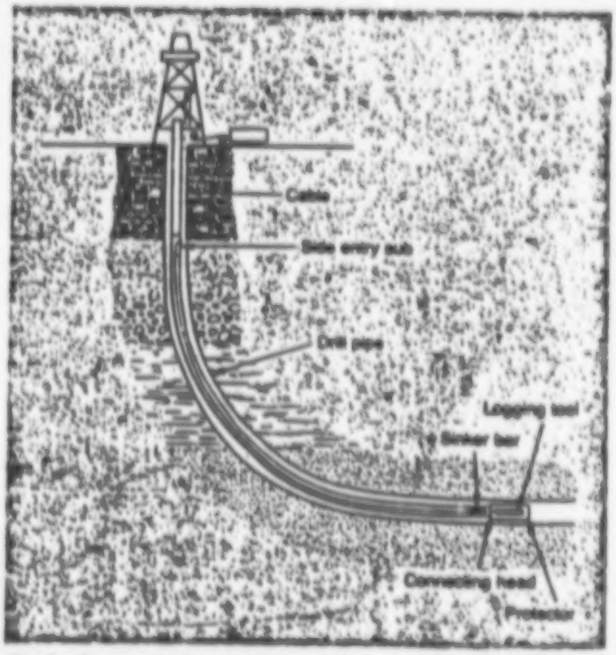

Fig. 5—Simphor horizontal logging system uses a wireline sinker bar and side-entry sub to connect power and recording cables to the logging tool that is run inside a protector sleeve at the end of the drill pipe.

of the pay zone in this well was about 1,542 ft, and it was surveyed in three runs, with each overlapping the following, to avoid log gaps. In the third horizontal well (Rospo Mare 6D), improvements in the system made it possible to record a complete set of logs in 9⅝-in. casing and also 8½-in. horizontal open hole.

With this technique, the logging tool is first fixed inside a specially designed protector (or container) that is then attached to the drillstring. The logging tool protector has a seven-connector electrical male plug on top, and normal procedure calls for the drill pipe and protector to be run to the top of the zone to be recorded. On the surface, a sinker bar, equipped with a seven-connector female plug at its lower end, is positioned and suspended in the last (top) joint of drill pipe. Logging cable is passed through the window of a side-entry sub and connected to the upper part of the sinker bar. The side-entry sub, which is similar to those used with the steering tool, is then screwed into the top joint of drill pipe.

By circulating mud, the sinker bar is pumped downhole until the two plugs connect at bottom. As soon as electrical connections are obtained, a mechanical anchoring system prevents opening of the electrical contacts. Engineers have designed the connectors in such a way that mud cannot remain between the contacts after connection. At this point, the logging tool can be powered and recording started as drill pipe is added to the string. When tripping drill pipe out of the hole, a second recording can be obtained, and the two logs compared.

During the trip out of the hole, when the side-entry sub reaches the surface, it is laid down, the electric cable disconnected from the logging tool, and the sinker bar system retrieved. The operation is then repeated for the next section of hole.

The number of logging sequences is determined by the depth of the first kick-off point (KOP) in the well. In fact, the side-entry sub must not be allowed to go below this KOP so as to avoid damaging the cable. Consequently, the deeper the KOP, the less the number of trips required.

On Lacq 91, with the first KOP at 289 ft, the operator logged the entire pay zone in three runs, each run surveying a section of open hole. While running in the well, the first run covered the interval segment between 2,526 and 3,005 ft. On the return trip, logging covered the 3,035–2,592-ft section. The second run logged from 3,012 to 3,481 ft twice—on both down and up trips. The third and final run completed the survey by logging the intervals between 3,560 and 4,026 ft (when running in the hole) and 4,052 to 3,530 ft (when coming out). At a depth of 541 ft, the side-entry sub was tipped nearly 9° without damaging the cable, and yet the procedure yielded simultaneous high quality dual induction, spontaneous potential and gamma ray logs.

On Rospo Mare 6D, the 2,228-ft-long, 8½-in. open hole was logged in only two runs as compared to three runs for Lacq 91. The reason for this was that the KOP of the first deviation was at a vertical depth of 1,640 ft, making it possible to locate the side-entry sub lower in the hole. Thus the two runs had an overlap of nearly 394 ft.

Horizontal logging of Rospo Mare 6D also involved using a borehole geometrical tool (four-arm standard centralized caliper) and gamma ray for the first log. This run was performed in two parts—from 5,479 to 6,234 ft for the first, and from 5,971 to 7,579 ft for the second. The four-arm caliper log has been proven worthwhile in horizontal drainholes, where in the case of Rospo Mare 6D it has shown position and sizes of voids and caverns several feet long.

For the second log, a variety of tools were used, including induction sonic gamma ray to register ISF-BHC-VDL-GR-SP with standard 3⅝-in. excentralized tools. The first run was performed in open hole from 5,332 to 6,381 ft and the second from 6,015 to 7,572 ft, the overlap being 364 ft.

Finally, for the third log, a dual laterolog/gamma ray with standard 3⅝-in. excentralized tools, was recorded both going in and coming out, from 5,364 to 6,733 ft in the first run, and from 6,480 to 7,563 ft in the second. Also, in the 8½-in. open hole, a log using a 2¾-in. density neutron gamma ray combination tool was run using pumped-down techniques. In the 9⅝-in. casing, using CBL-GR-CCL standard 3⅝-in. centralized tools, logs were recorded between 3,839 and 5,364 ft with Simphor. Inclination at the high point was 33°, that of the lower was 80°. As an alternate means of logging, Schlumberger ran a standard sonic gamma ray neutron mounted on a roller-centralizer device. It moved down by gravity to 5,052 ft, where hole angle reached 78°.

In conclusion, it appears that all logs gave excellent quality and repeatability. This was easily confirmed by overlapping sections. Interpretation of the logs run in the horizontal drain hole is very new and of great interest, particularly if a comparison can be made with data collected in a vertical well in the same field. Moreover, the advantages of Simphor include the ability to maintain mud circulation during logging, use of logging tools with larger diameter and increased power and efficiency, and the capability of perforating with a 4-in. gun, setting packers, etc.

COMPLETION AND WORKOVER OPERATIONS

Stimulation. Both Lacq wells were completed with a 7-in. slotted liner. After several months of production, it appeared that workovers would be required to improve productivity and to reduce water cut.

Lacq 90 was acid-washed along the 886-ft section within the reservoir. This was done by displacing acid plugs along with four gel plugs to ensure good dispersion in the horizontal hole. This operation considerably improved the productivity index of the well.

Fracture plugging. After initial completion, Lacq 91 produced mostly water, which came from a large fracture at 3,448 ft, the same point at which total mud loss occurred during earlier drilling operations. To eliminate this problem, the previously installed liner was pulled and the fracture sealed by pumping in gel, sand and cement. A new liner system then was run. From bottom to top, it consisted of slotted pipe, two external inflatable packers to isolate the fractured zone and standard (non-slotted) pipe above. After the liner was run, it was cemented from the top packer to the liner hanger. The well was then completed with production coming from the slotted liner section. Plans are to convert the well to a dual completion by perforating another zone above the packers and running a second tubing string.

CONCLUSIONS

Successful operations conducted on the three wells confirm that it is possible to drill horizontal drainholes provided sound engineering, close supervision and quality services are applied. Heavy-oil recovery, steam injection, fractured reservoirs and large but thin reservoirs may be primary applications. However, more work still must be done, both to improve drilling technology (thus lowering costs) and to test completion and stimulation techniques. This technology should be evaluated if the methods are to become common practice.

The author

Marc Dorel graduated from the University of Lille (France) in 1966 with a doctorate in applied mathematics. He joined the French oil company Total-CFP, where for five years he conducted the first programs in seismic numerical data processing. Later he became a drilling engineer, and from 1974 to 1977 was in charge of the Drilling Technical Management Group assigned to develop Mereksenstah oil field in southern Algeria. From 1977 to 1979 he directed the French Deep Sea Drilling Project, a cooperative effort by Elf-Aquitaine, IFP and Total. In 1979, he joined IFP (the French Petroleum Institute), where he is in charge of the Drilling and Completion Unit.

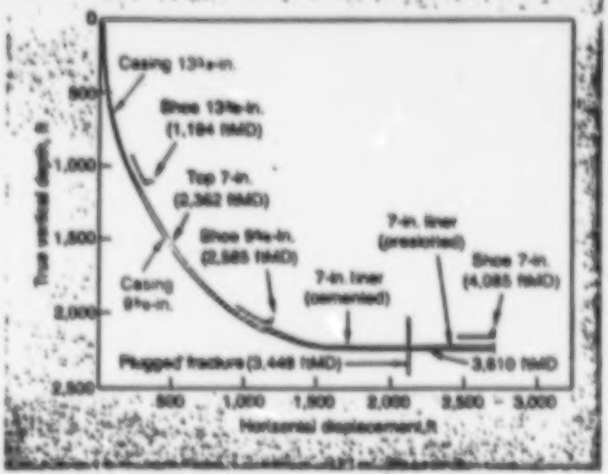
True vertical depth, ft
0
500
1,000
1,500
2,000
2,500
Casing 13 3/8-in.
Shoe 13 3/8-in. (1,184 tMD)
Top 7-in. (2,362 tMD)
Shoe 9 5/8-in. (2,585 tMD)
Casing 9 5/8-in.
7-in. liner (cemented)
7-in. liner (preslotted)
Shoe 7-in. (4,085 tMD)
Plugged fracture (3,448 tMD)
3,610 tMD
500
1,000
1,500
2,000
2,500
3,000
Horizontal displacement, ft

Fig. 6—Completion sequence for Lacq 91, shows positions of various casings, liners and a fracture that was plugged during completion. A unique dual completion allows the well to produce through a slotted liner below the fracture, and through perforated cemented liner above the fracture.

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THREE HORIZONTAL HOLE PATTERN

by

G.E. Pugh
Texaco Canada Resources Ltd.

ABSTRACT

Between October 1980 and February 1981, Texaco Canada Resources Ltd. drilled three horizontal parallel holes in soft, shallow, unconsolidated Athabasca Tar Sands at their Fort McMurray Pilot Plant, Alberta, Canada.

Objectives of the project were to produce bitumen at very shallow depths with minimum drilling cost, lease cost and environmental impact. The accomplishment is believed unique in that all three wells were drilled from the same drilling pad, each well being spudded in at a vertical angle of 45°, and a horizontal attitude was achieved at a true vertical depth from surface of approximately 125 m (410 ft.). Over 35 m (1000 ft.) of horizontal hole was drilled to complete each well, the horizontal portions being parallel to each other.

A new, innovative, hydraulically operated drilling rig was built for this project with a 110,000 kg (240,000 lb.) hoist and 22,700 kg (50,000 lb.) push-down capacity. New techniques were developed to drill, enlarge and underream the horizontal hole up to 368.3 mm (14½") diameter. Mud motors were used to power the bit and the force on the bit was accomplished by pushing down on the drill pipe.

INTRODUCTION

Texaco Canada Resources Ltd.'s Fort McMurray Pilot Project is in the Athabasca Tar Sands deposits and located 19 km southeast of the city of Fort McMurray (Figure 1). The bitumen from these deposits is extremely viscous with a pour point in the order of 21°C (70°F). Typical properties of the bitumen are:

Gravity API:	7° - 9°
Specific Gravity at 15°C	1.007
Nature at ground temp.of 7°C:	Solid
Viscosity at 205°C:	10 CP
Carbon Content:	81.8%
Sulphur:	5.3%

The deposits vary in thickness from stringers to over 60 m (200 ft.). The overburden ranges from surface exposure to in excess of 550 m (1800 ft.). Approximately 10% of this tar sand is considered to be strip mineable, so that many companies operating in the Athabasca area have concentrated on experimental in-situ methods of recovery.

At Texaco's McMurray lease, the tar sands are approximately 45 m (150 ft.) thick but comprise a heterogenous layered mixture of bitumen, sand and clay with occasional hard shale stringers. While the pore space is partially gas and water saturated, there is no initial formation pressure. The overburden is 76 m (250 ft.) thick and consists of the Clearwater formation shales, sands, and sandstone stringers, covered by soft glacial till containing gravel and rock boulders. The surface is made up of muskeg with shallow lakes, interspersed by dry, higher ridges. Core hole drilling is normally done in the winter months when the muskeg is frozen solid as the terrain is largely impassable for the rest of the year. For continuous operations, one to two metres of clay fill are packed over the muskeg for roads and drilling and production pads.

Texaco has operated an experimental steam flood using vertical wells on its McMurray lease since 1972. The initial Pattern I was a 4 hectare (10 acre) 9-spot with central injection while the next Pattern II started in 1976 was a 1.2 hectare (3.75 acre) enclosed 7-spot with central and peripheral steam injection. Over 500,000 bbls. have been recovered to date from these two patterns with indicated recoveries approaching 100,000 bbls./acre from Pattern II. However, economic analyses indicated that further improvements would be required to provide for acceptable recovery of capital and operating costs.

The use of long horizontal drain-holes appeared to be the best way of reducing capital costs while providing for improved recovery. Since the flow capacity of wells is generally proportional to the pay thickness, a 300 metre (1000 ft.) horizontal well bore could replace 7 vertical wells. This provides a significant reduction in the required roads, drilling pads, steam and flowlines, and associated manifold and test facilities. In addition, the environmental impact of development is greatly reduced. If the horizontal well bore is located near the base of the sand, improved performance may be expected due to gravity effects in the reservoir.

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In 1979 ~~the Company~~ initiated a program to drill three long horizontal and parallel wells at the McMurray pilot from a single drilling pad. This required a drilling rig capable of operating at unusual off-vertical angles, a pushdown capability to apply force to the bit in the horizontal hole, adequate pump capacity to run down-hole hydraulic motors for directional drilling and a large power swivel for drill-string rotation when required.

[illegible] drilling [illegible]

At that time, no rig was known to exist which would meet these requirements, which amounted to an oil-well drilling rig with mine boring adaptations. Enquiries to drilling contractors in Alberta resulted in Texaco Canada Resources Ltd. entering into a contract with Westburne Drilling (Canada) Ltd. to provide and operate a custom rig to be made by E.A. Kutryk Industries Ltd. of Calgary, with a specification listed in Table 1. This rig was operated hydraulically for both pulling up, pushing down and rotating the drill pipe. Conventional blocks and wireline were not used, a conventional power swivel on a hydraulic-ram motivated trolly, sliding up and down the mast, being the connection to the drill pipe. Because of anticipated difficulties in handling normal drill pipe tongs at 45°, a hydraulically powered spinning and torque wrench was incorporated into the mast structure for making and breaking pipe joints. Figure 2 shows some aspects of the rig.

The remainder of the rig, including the drilling mud circulating system, followed conventional practice. The substructure height of 4.6 m (15 ft.) allowed use of a complete blowout preventor stack.

DRILLING CONSIDERATIONS

In designing the drilling program the following factors were kept in mind:

1. All three wells would be drilled from one drill pad with wellheads 9 m (30 ft.) apart.
2. The horizontal portions of each hole were to be drilled at 125 m (410 ft.) depth, be parallel to each other and spaced 125 m (410 ft.) and 75 m (246 ft.) apart.

3. A maximum change of angle rate of 5°/30 m (5°/100 ft.) was specified to minimize tubular stress and reduce pipe drag.

4. The glacial till is very soft, while the tar sands consist of loose sand bonded by bitumen.

5. Wells would be used both for injection of steam etc. and production of bitumen.

6. As sticking of casing/liner was possible, while being run, sizes should be such that a smaller diameter liner could be run through the first liner if it became stuck before reaching total depth.

7. The mud system would have to power the mud motors, provide maximum friction reduction for oil well tubulars and clean the hole effectively.

8. The mud temperature could not be allowed to go above 18°C (65°F) and should be maintained somewhat lower.

9. Force on the bit had to be provided by pushing down on the drill string.

10. Continuous read-out of direction and inclination of hole would help to ensure the hole remained on the desired course.

11. Design temperatures for casing and tubing to be saturated steam at 2165 kPa (314 psia) equivalent to 216°C (421°F).

12. To obtain information on downhole temperatures, during injection and producing operations, thermocouple strings would be run if possible.

DRILLING PROGRAM

To accomplish the objectives and meet the above considerations, the following drilling program was prepared. (All depths are as drilled, unless noted as True Vertical Depth (TVD), the latter being the vertical depth from surface).

1. Preset, by pile driving, approximately 20 m of 508 mm (20 in.) 139.8 kg/m, 11 mm wall, grade H-40, buttweld pipe as conductor, at an angle of 45°.

2. Drill, with mud motor, 245 mm (9-5/8") pilot hole from 20 m (15 m TVD) to 130 m (94 m TVD), building angle at approximately 5° per 30 m. Continuous surveys to be obtained from steering tool with confirmation from Multishot survey.

3. Ream hole to 375 mm (14-3/4") with hole opener.

4. Run 130 m, 273 mm (10-3/4") 82.6 kg/m, MN 80 BTC, API casing with special centralizers designed to impart a swirl to cement.

5. Cement with oilwell thermal cement.

6. Displace old drilling mud to polymer mud, with lubricant additives.

7. Drill from 130 m (94 m TVD) to 300 m (120 m TVD) building angle at 5° per 30 m with 245 mm (9-7/8") bit to achieve an angle of approximately 90°. All drilling to be with mud motor and using steering tool.

8. Drill ahead w/245 mm bit to achieve as much horizontal hole as possible (Target: 300 m).

9. Run in liner consisting of approximately 480 m, 193.7 mm (7-5/8") 50.15 kg/m, MN 80 BTC API casing slotted with 0.030 slots. Land liner packer to approximately 120 m with liner shoe 1 m above bottom of hole.

10. Run 450 m, 114 m (4½") 22.5 mg/m, N80, 8 RD LT & C, API casing, as tubing string, with thermocouple string, pre-installed in 25.4 mm endless tubing and strapped to 114 mm tubing, the shoe to be approximately half way down the slotted section of the 193.7 mm line.

11. Install wellhead and thermocouple connections.

The plan for these wells is shown in Figure 3. To ensure that the mud temperature would not exceed 18°C (65°F) a mud chilling system was installed. A slip-stream from the mud tank could be directed through the chiller of a refrigeration system, as required.

The polymer mud system chosen gave maximum lubrication while meeting all other conditions. An oil-base mud would have given better conditions for running casing, but at low mud temperatures, the viscosity would have been unacceptably high and would have created extremely high pump pressures.

OPERATING DATA

Figures 4,5,7 & 9 show the drilled path of the holes while figures 6,8, and 10 show drilling progress on a time basis for both true vertical depth and measured (drilled) hole depth.

The 300 m target for the horizontal portion of the hole was achieved in all cases, although the path to the target was not exactly as planned. A time analysis of the three holes shows that while the first hole, H-1, was delayed by 6 days for rig repairs and modifications, 18 days were lost while drilling hole H-3 because of bad hole conditions resulting in tight hole and stuck pipe.

COMPLETION

Figure 11 shows the completion of hole H-3 which is typical for all three horizontal holes. Both the 273 mm (10-3/4") casing and 194 mm (7-5/8") liner were grade N80 API with buttress threaded collars to withstand thermal expansion without exceeding yield strength.

The surface casing is cemented with a thermal cement containing 40% silica flour. The liner has slots over the horizontal portion only of the hole and is not gravel packed. The packer at the top of the liner does not have slips in order that initial thermal expansion will not be restrained.

The tubing is a string of 114 mm (1½") N80,API 8RD thread casing joints. The pump seating nipple (PSN) is provided for a downhole pump and the slotted section below the PSN is intended to give more even distribution of steam during the injection phase of operations. The choice of 114 mm tubing sizes inside the 194 mm liner, is to give theoretical minimum pressure drop to steam injected down both tubing and annulus.

Not shown in Figure 11 is the 25.4 mm (1 in.) endless tubing which contains the thermocouples for well temperature observation and which is anchored to the shoe of the 114 mm tubing.

EQUIPMENT PERFORMANCE

(a) Drilling Rig

It was found that a disproportionate amount of the total time to drill these horizontal holes was taken by running drilling assemblies in and out of the hole. The rig was designed to pick up and lay down drill pipe by single joints only and a good pipe handling system is very necessary. Equipment and techniques to handle the pipe were steadily developed and are now at an acceptable level.

The hydraulic system for pulling up, pushing down and rotating the drill pipe proved satisfactory after initial problems were overcome, even when temperatures were as low as -36°C (-30°F).

(b) Downhole Tools

The angle build-up drilling assembly consisted of a 245 mm (9-5/8") long-tooth rock-bit, powered by 6½" Dynadrill and Navidrill mud motors with a bent sub to give the necessary "kick". Various bent subs with angles ranging from ½° to 4° were available. This assembly was used for drilling all holes, including the horizontal drilling assembly to counteract any tendency to drop off.

Above the drilling assembly, three non-magnetic drill collars were run for directional surveys. This number was a minimum to reduce magnetic interference in very high angle surveys, to negligible proportions. Heavy weight drill pipe 114 mm (4½") 61 kg/m (41 lb/ft.) was used to surface. This provided a stiffer than normal drill string between bit and surface push down force to give better directional control. In the third hole, H-3, some normal weight 114 mm drill pipe was successfully used in the horizontal section to reduce drill string drag, and allow drilling further with the same push down force.

No problems in building up angle were encountered, even in the very soft formations. The actual force on the bit could not be measured due to hole drag, but the very soft formation required only a light force.

Hole opening was accomplished by rotating the drill pipe with a blade hole opener on bottom. The nose of the opener mounted a non-rotating 245 mm (9-5/8") stabilizer which readily followed the original hole with no tendency being detected to bury itself, and start a new hole.

(c) Directional Surveys

Accurate knowledge of the location of hole and direction of progress at any time was vital to the successful drilling of these wells. A steering tool was used at all times while drilling. Located in the non-magnetic drill collar string and connected to surface by wireline, this tool provided constant surface digital data on hole inclination and azimuth. The tool generally worked well, but the necessary wireline caused considerable inconvenience. Also the tool has to be located so that a non-magnetic drill collar is between the tool and mud motor/bit, which means that information is some 15 m (50 ft.) late. Careful attention to directional trends is required.

To confirm steering tool directional information, multi-shot surveys were run. Reasonable correlation was obtained.

(d) Mud System

Use of a simple aquagel/bentonite mud to the top of tar sands, and a polymer mud within the tar sands, proved satisfactory. Desanders and a centrifuge mud cleaning system were necessary at all times to keep solids to a minimum and reduce wear on the mud motors. Ambient temperatures were low enough that the chilling system was not required. However, an inadvertant heating of the mud system on one occasion to approximately 25°C (77°F) quickly resulted in sticky hole conditions, confirming that higher ambient temperatures would have required use of the mud chilling system.

HOLE PROBLEMS

(a) Wash Out Below Surface Casing

This was encountered on holes H-2 and H-3 and, is believed, due to the pile-driven conductor shoe being in a soft clay formation. The wash out resulted in difficulty in re-entering into previously drilled hole and was overcome only by repeated cement plugging and redrilling.

(b) Tight Hole

In the third hole, H-3, tight spots were encountered, due to swelling bentonitic clays and/or tar with low sand content gradually flowing into the hole. This resulted in repeated reaming while drilling, and difficulties in running the liner.

(c) Hole Drag

Hole drag was such that, with heavy weight drill pipe, and the mud system used, the rig capability was no more than 600 m (1968 ft.). Substitution of standard drill pipe for some of the heavier pipe in the horizontal section noticeably reduced drag and allowed hole H-3 to be drilled to 629 m (2064 ft.). In all cases, it was found necessary to augment the 22,750 kg (50,000 lb.) rig push down with drill collars at the top of the string to speed up running in of pipe into the hole and obtain sufficient force on bit for drilling ahead.

(d) Running Liner

The increased surface area and light weight of the 194 mm (7-5/8") liner resulted in extremely slow running time. For example in hole H-1, 32 hours were required. On Hole-3, the above-noted tight spots resulted in the liner parting at 170 m (558 ft.) while attempting to work the liner into the hole. The portion left in the hole was successfully fished out. To run the liner in this hole, horizontal underreaming of the hole to 368 mm (14½"), and a means of circulating the liner while running in, were successfully developed.

COSTS

The cost of these first horizontal holes were 5 to 6 times that of a vertical hole. In terms of sand exposure, the equivalent of more than seven vertical holes were drilled in an average horizontal hole. These relative costs reflect the experimental nature of the project using new, unproven equipment, the necessity to modify conventional equipment and develop new drilling techniques, together with time necessary to train people in this horizontal hole concept. It may be expected that, with modifications and development of equipment, and with further experience, that the costs would be significantly reduced.

FUTURE IMPROVEMENTS

Expansion of in-situ recovery methods in the Athabasca Tar Sands to the commercial stage will require further development and improvement of horizontal hole equipment and techniques. The following merely list items for further improvements.

1. Pipe handling equipment, to reduce rig time.
2. Increased push down capability, to reduce use of drill collars.
3. Extension of the rig range by using lighter drill tubulars and mud lubricants.
4. Development of completion techniques with regard to liners, gravel packing and tubing.
5. The bit direction control and monitoring read out systems to reduce tripping of the assembly.

SUMMARY

Drilling the three parallel horizontal holes in very shallow, unconsolidated tar sands for in-situ recovery of bitumen by thermal processes is believed to be unique. The objectives were all achieved, though not without unforeseen difficulties and additional costs. New drilling techniques and equipment were successfully developed so that the drilling of similar holes in future tar sands projects can be considered a viable alternate to conventional, vertical holes.

Perhaps the biggest problem overcome by those most closely associated with the project is an adjustment to thinking horizontal. Such a well is not a vertical one on its side.

ACKNOWLEDGEMENTS

The author wishes to thank Texaco Canada Resources Ltd. for permission to publish this paper. The assistance given by fellow workers in the Oil Sands Group of the Company, especially Messrs. D.C. Loxam and I.E. Varga, also that of E.A. Kutryk Industries Ltd. and Westbourne Drilling (Canada) Ltd. is most appreciated.

TABLE I

KUTRYK KS-1 HYDRAULIC SLANT-HOLE RIG

KB to Ground
At 0° - 3.95 m
At 45° - 5.55 m

Bottom of Table Beam to Ground
At 0° - 3.65 m
At 45° - 5.10 m

Hydraulic System:	34,000 kPa skid mounted.
Max. Lifting Capacity:	110,000 daN w/450 kW to ram.
Max. Hoisting Travel:	13.70 m.
Max. Hoisting Speed:	10 sec. per single.
Hoisting Speed @ Full Load:	35 sec. per single.
Prime Movers:	2 GM 6-71 'N' Series Twin sets.
Mast:	Kutryk 16.75 m single section w/175,000 daN capacity.
Max. Angle:	0° to 45° in 5° increments.
Substructure:	Box type 3.95 m H x 5.50 m L x 3.65 m W.
Power Swivel:	Bowen S3.5 track mounted in derrick w/attachments for casing elevators. Provides 850 daN/m torque @ 150 rpm.
Pump:	National K-500-A w/Hydril K-20-3000 pulsation dampner.
Pump Power:	2 - GM 8V-71 'N' Series w/12V-71 radiators and Allison 855 torque converters.
Mud System:	Unitized skid mounted w/3 compartments complete w/GM powered low pressure system for mixing and/or agitation and fitted w/high pressure roll for mixing and/or agitation. 45 m³ capacity.
Shaker:	2.25 kW Link Belt NRM 145 w/1.21 m x 1.52 m screens.
Water Tank:	45 m³ capacity, mounted on skid w/toolhouse. Features drop in doghouse.
Toolhouse:	On skid w/water tank/doghouse unit. 4 m L x 3.04 m W and includes oil storage.
Power Plant:	2 - Cat 315 engines w/30 kW generators. Housed in combination building with accumulator and change house.

FIG. 1

OIL SANDS OF ALBERTA

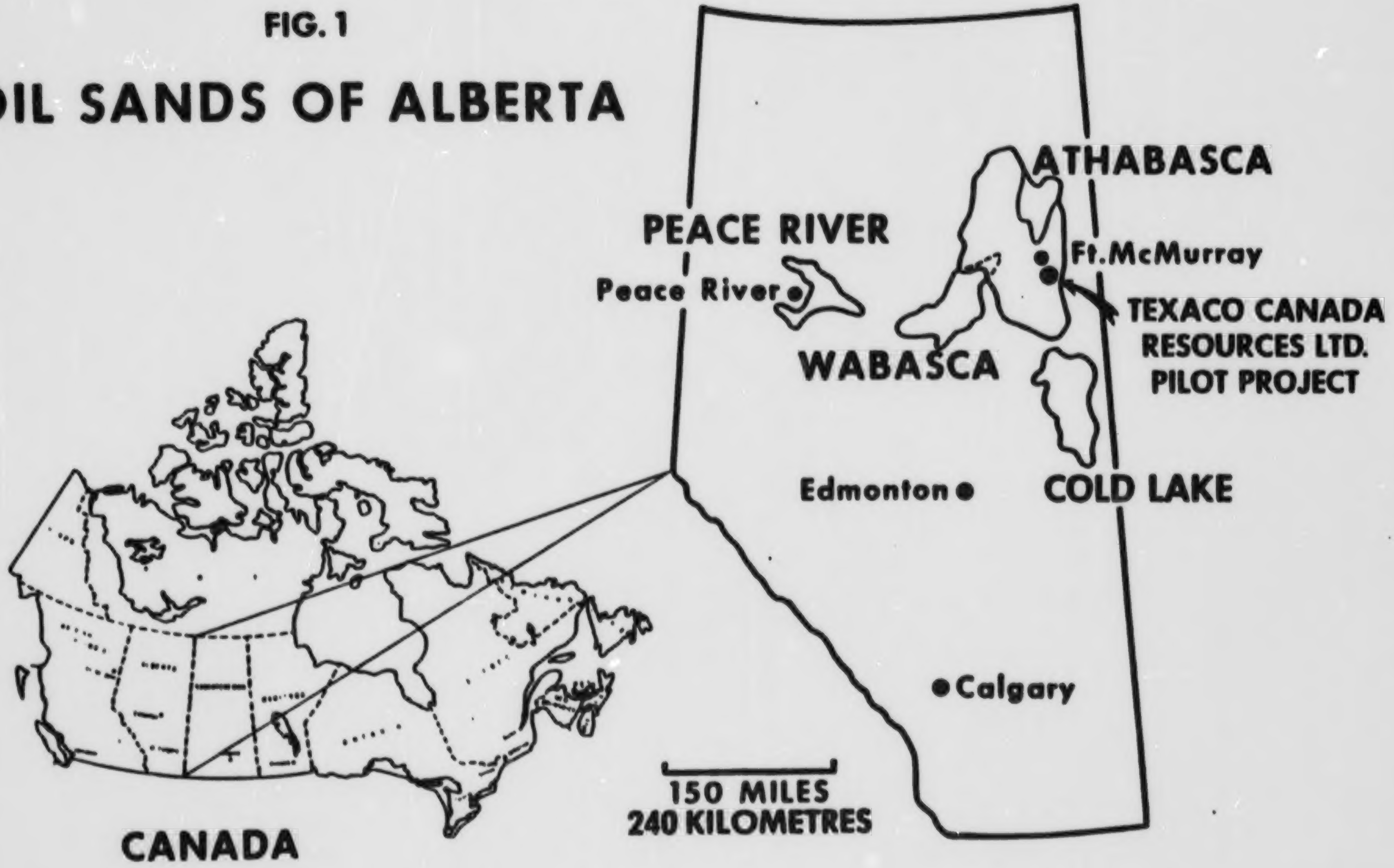
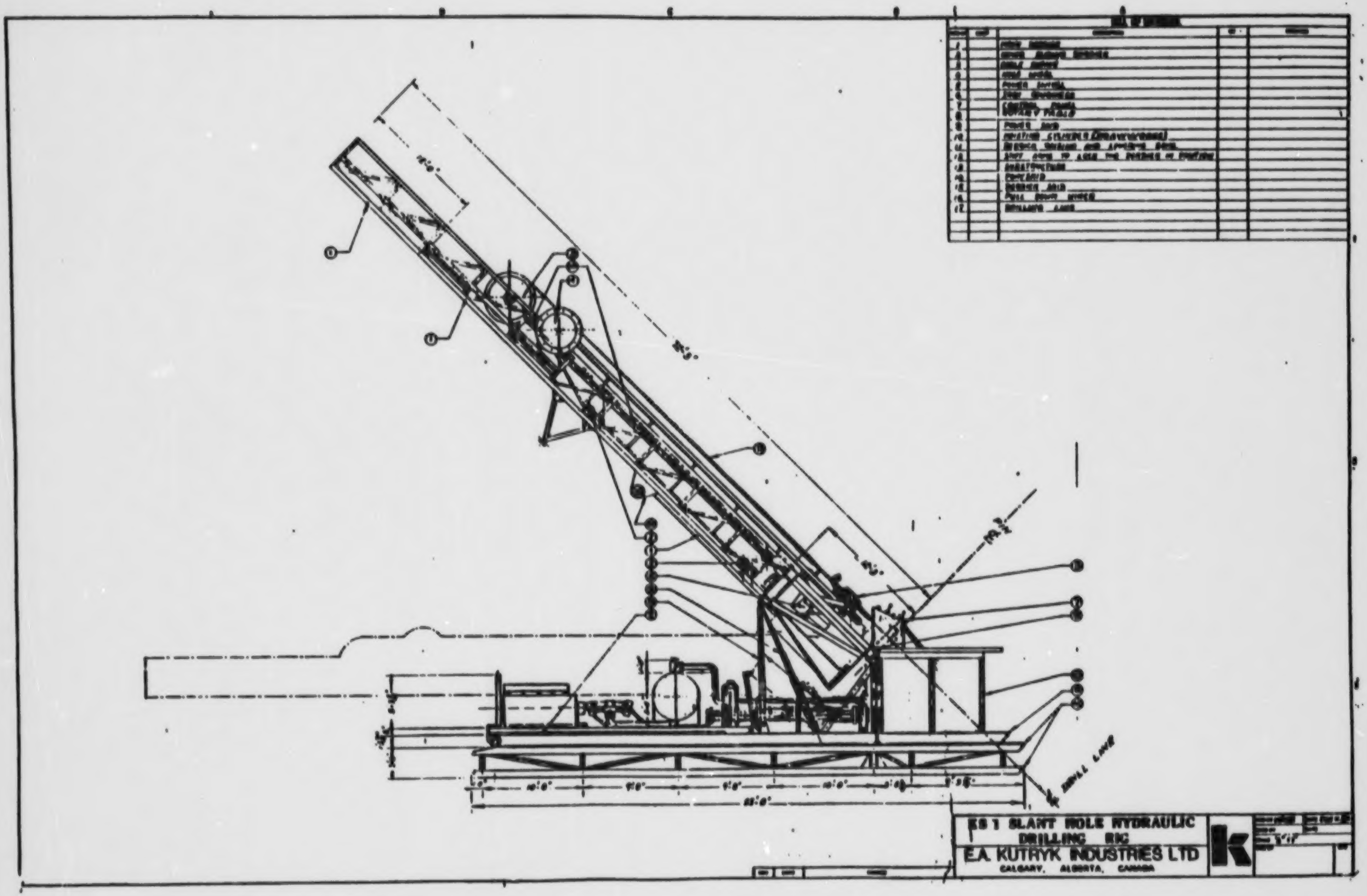

ATHABASCA
PEACE RIVER
Ft.McMurray
Peace River
TEXACO CANADA RESOURCES LTD. PILOT PROJECT
WABASCA
Edmonton
COLD LAKE
Calgary
150 MILES
240 KILOMETRES
CANADA

FIG. 2

FIG. 2



ES 1 SLANT HOLE HYDRAULIC DRILLING RIG
E.A. KUTRYK INDUSTRIES LTD
CALGARY, ALBERTA, CANADA
DRILL LINE

FIG. 3

HORIZONTAL HOLES H1 H2 AND H3 D
DRILLING PROGRAM

PLAN

50 m

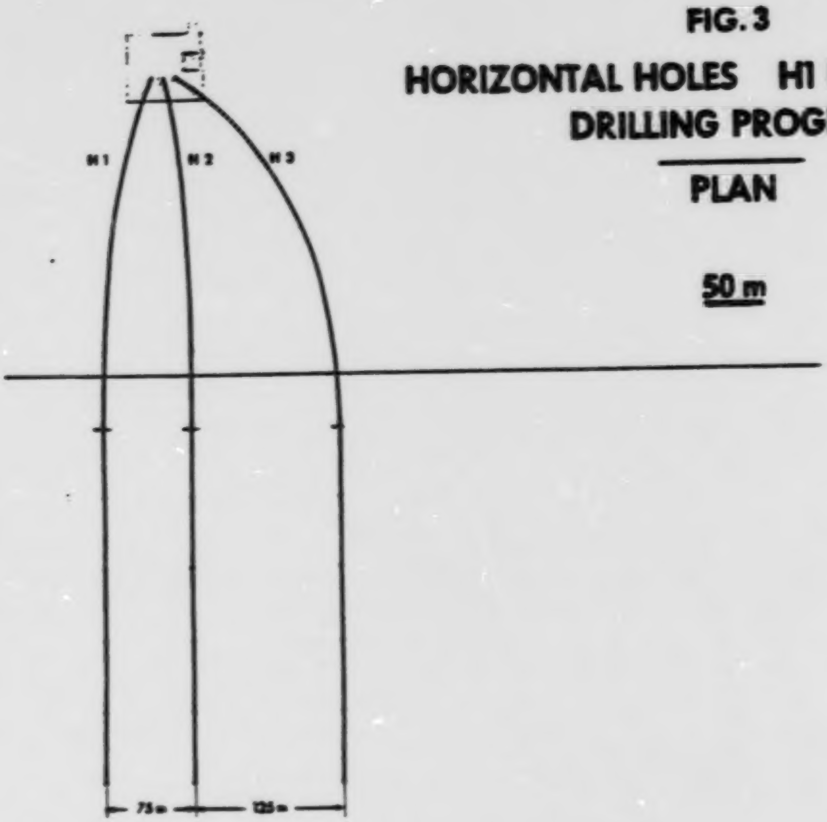
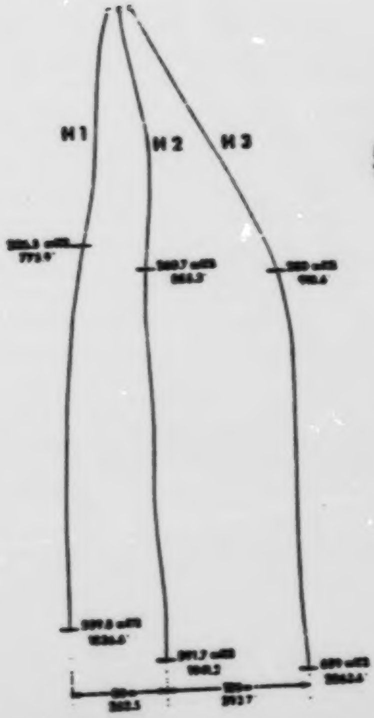

H 1
H 2
H 3
75 m
125 m

FIG. 4

ATHABASCA PILOT PROJECT
HORIZONTAL HOLES AS DRILLED

CONFINED 9.3 ha (20 ACRES)



50 m

FIG. 5

HORIZONTAL DRAIN HOLE H-1

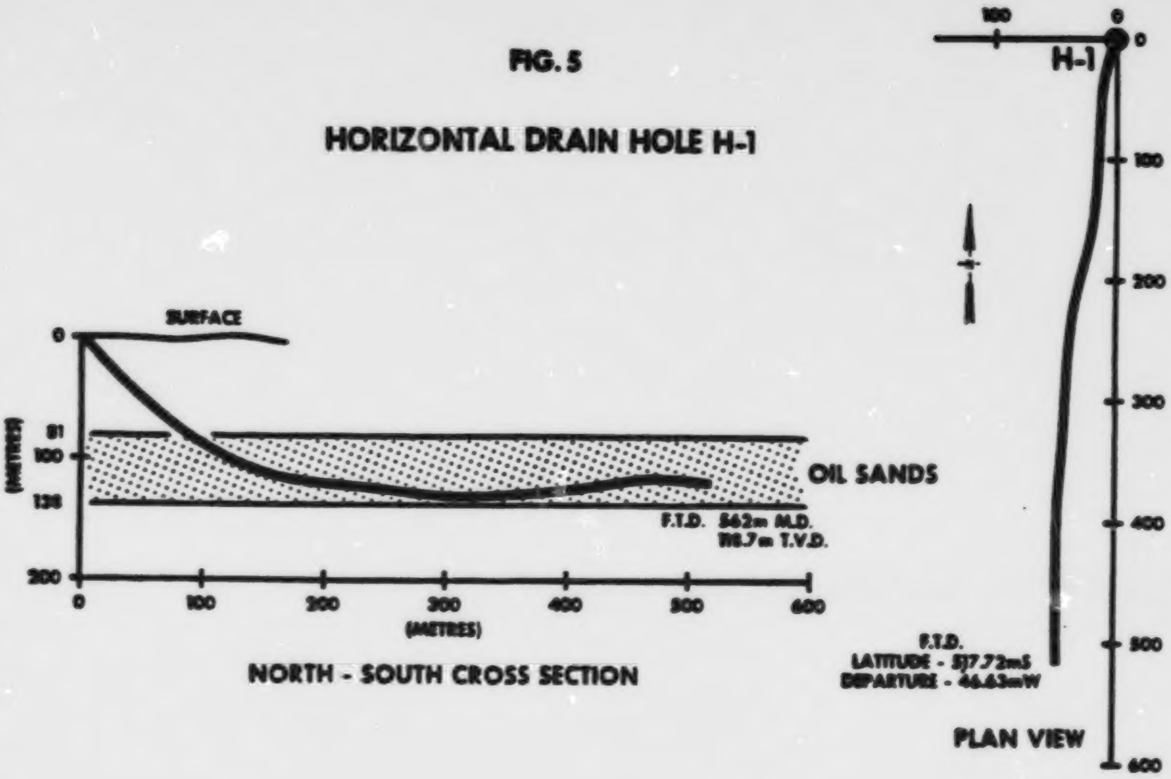

SURFACE
0
81
100
138
200
(METRES)
OIL SANDS
F.T.D. 562m M.D.
118.7m T.V.D.
0
100
200
300
400
500
600
(METRES)
NORTH - SOUTH CROSS SECTION
100
0
H-1
0
100
200
300
400
500
600
F.T.D.
LATITUDE - 517.72mS
DEPARTURE - 46.63mW
PLAN VIEW

FIG. 6

H-1 DEPTH VS DAYS

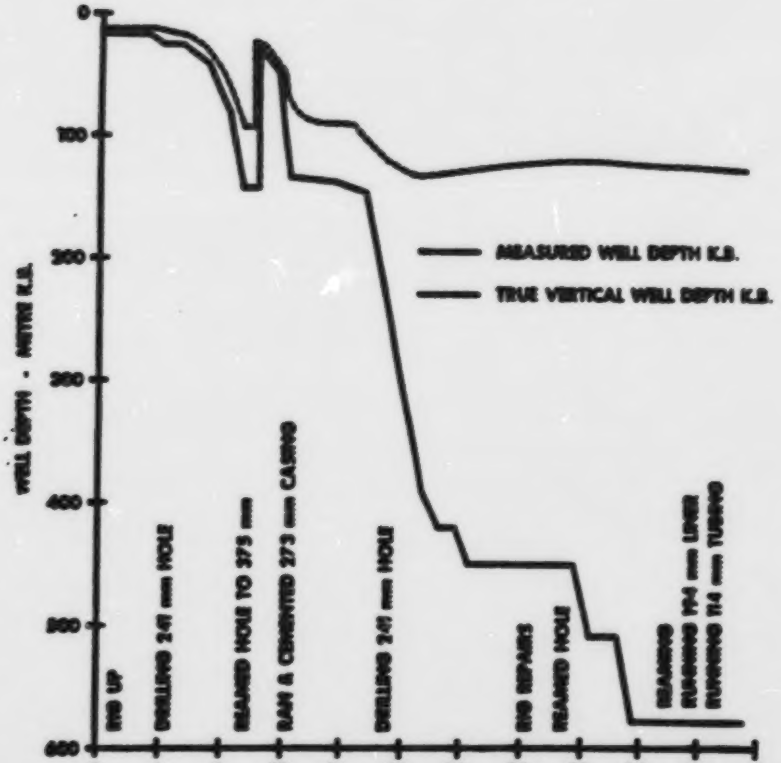
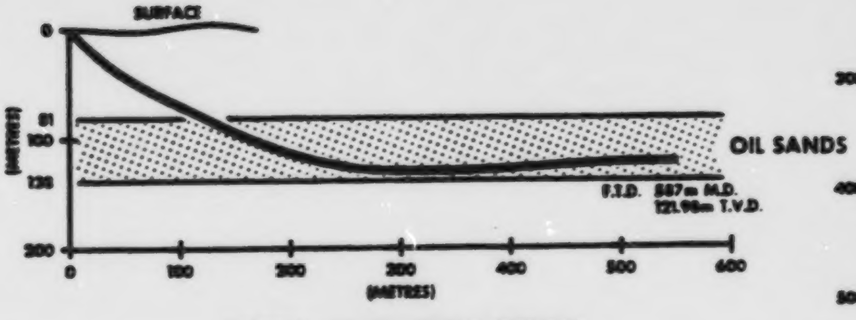
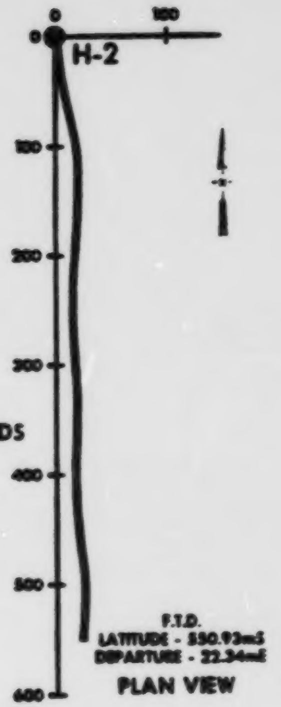


FIG. 7

HORIZONTAL DRAIN HOLE H-2


SURFACE
0
81
100
120
200
(METRES)
OIL SANDS
F.T.D. 557m M.D.
121.98m T.V.D.
0
100
200
300
400
500
600
(METRES)

NORTH - SOUTH CROSS SECTION


0
100
0
H-2
100
200
300
400
500
600
F.T.D.
LATITUDE - 550.93mS
DEPARTURE - 22.34mE

PLAN VIEW

FIG. 8

H-2 DEPTH VS DAYS

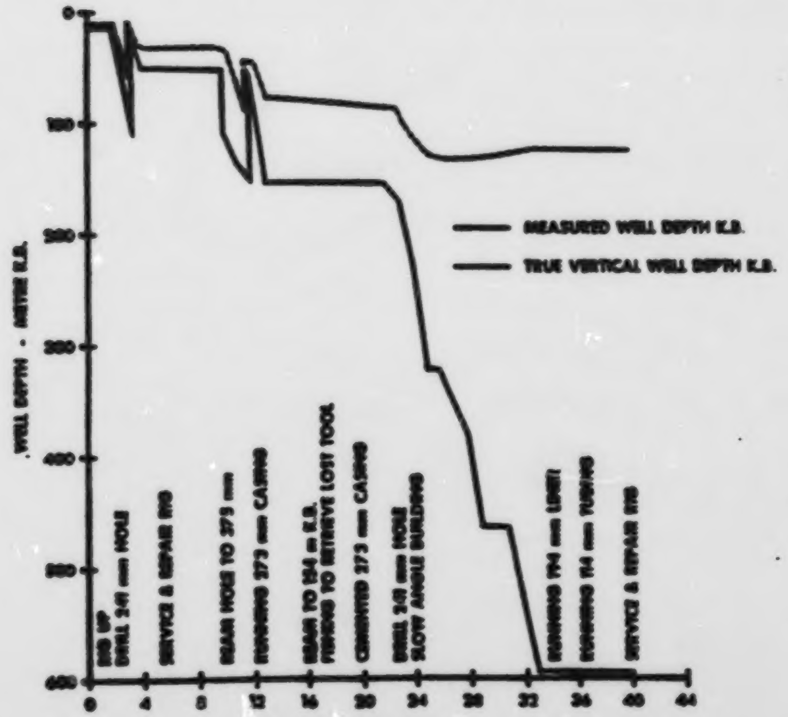
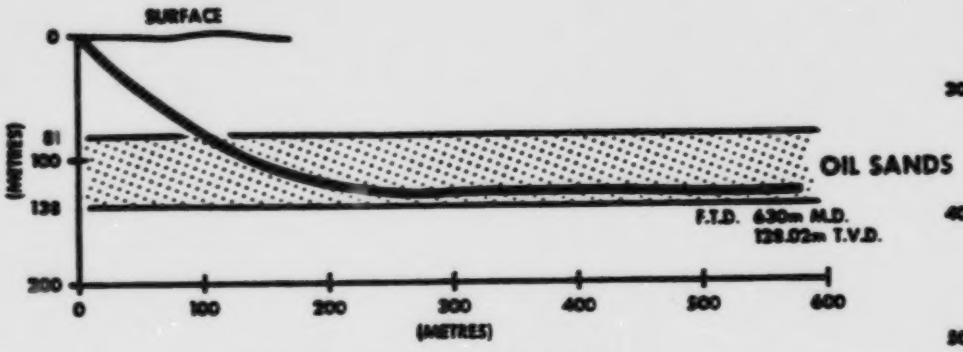
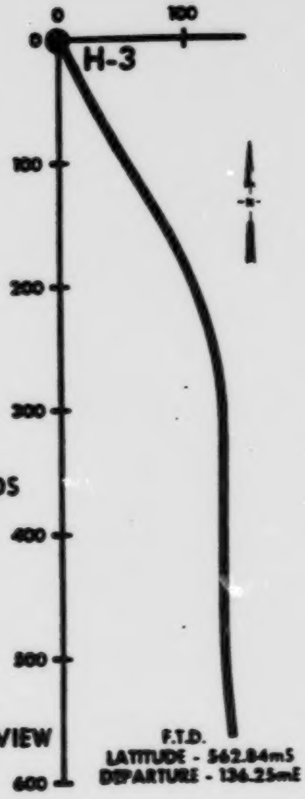


FIG. 9

HORIZONTAL DRAIN HOLE H-3


SURFACE
0
81
100
138
200
(METRES)
OIL SANDS
F.T.D. 630m M.D.
128.02m T.V.D.
0
100
200
300
400
500
600
(METRES)

NORTH - SOUTH CROSS SECTION


0
100
0
H-3
100
200
300
400
500
600
F.T.D.
LATITUDE - 562.84mS
DEPARTURE - 136.25mE

PLAN VIEW

FIG. 10

H-3 DEPTH VS DAYS

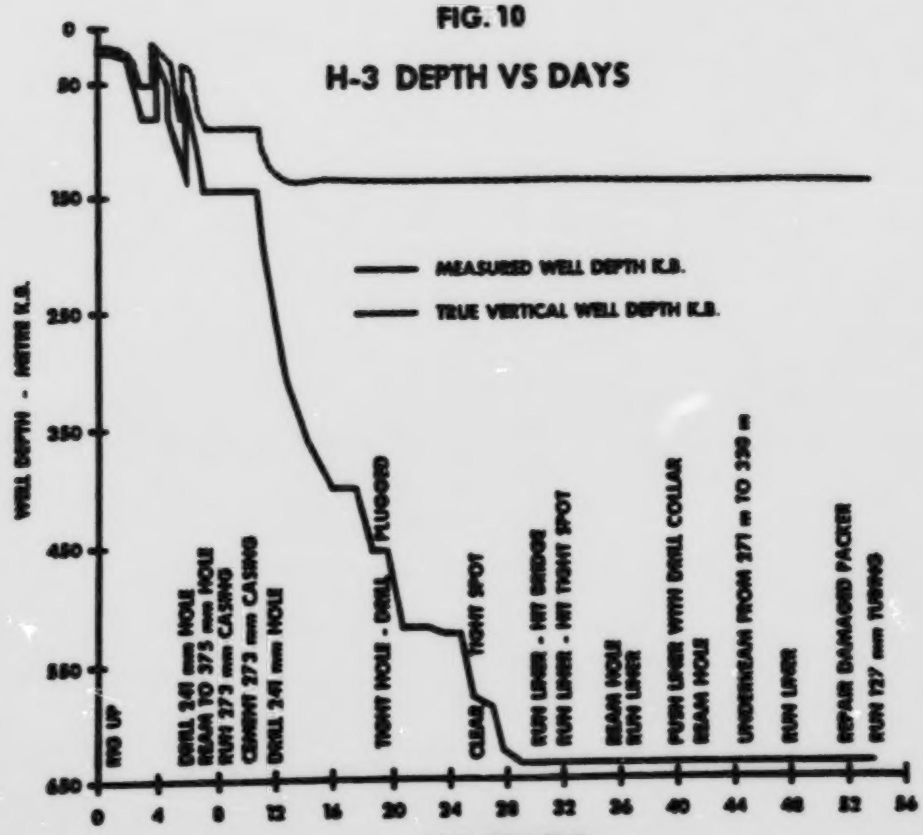
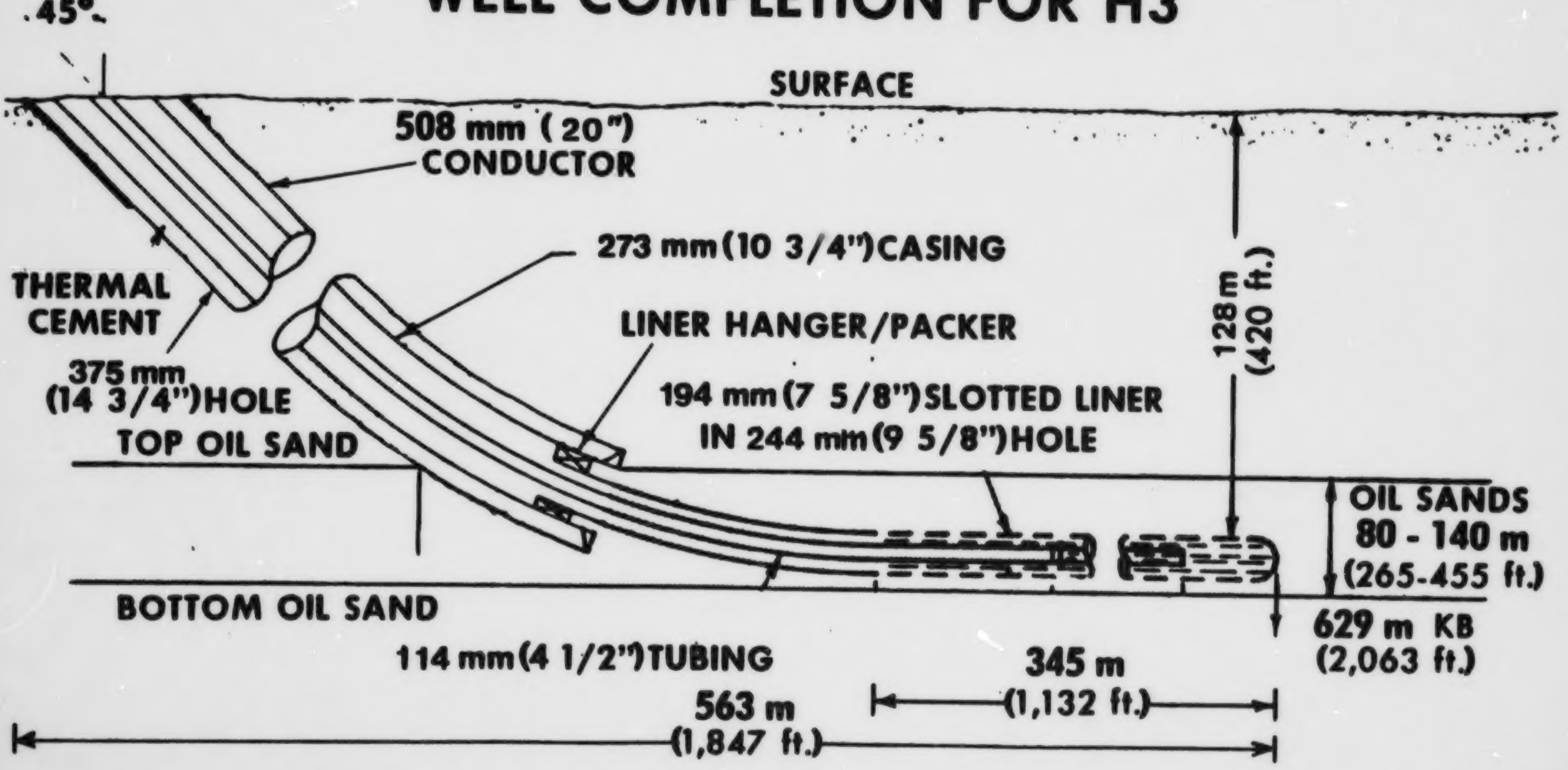


FIG. 11

ATHABASCA PILOT PROJECT
PATTERN III
WELL COMPLETION FOR H3



.45°
SURFACE
508 mm (20")
CONDUCTOR
THERMAL
CEMENT
375 mm
(14 3/4")HOLE
273 mm(10 3/4")CASING
LINER HANGER/PACKER
194 mm(7 5/8")SLOTTED LINER
IN 244 mm(9 5/8")HOLE
128 m
(420 ft.)
TOP OIL SAND
BOTTOM OIL SAND
OIL SANDS
80 - 140 m
(265-455 ft.)
629 m KB
(2,063 ft.)
114 mm(4 1/2")TUBING
345 m
(1,132 ft.)
563 m
(1,847 ft.)

008463

Alberta OIL SANDS INFORMATION CENTRE

PETROLEUM SOCIETY OF CIM

PAPER NO. 82-33-68

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17

DRILLING OF THREE HORIZONTAL HOLE PATTERN FORT McMURRAY, ALBERTA

by
G.E. Pugh
Texaco Canada Resources Ltd.

PUBLICATION RIGHTS RESERVED

THIS PAPER IS TO BE PRESENTED AT THE 33RD ANNUAL TECHNICAL MEETING OF THE PETROLEUM SOCIETY OF CIM HELD JOINTLY WITH THE 6TH SYMPOSIUM ON ENGINEERING APPLICATIONS OF MECHANICS IN CALGARY JUNE 6 — 9, 1982. DISCUSSION OF THIS PAPER IS INVITED. SUCH DISCUSSION MAY BE PRESENTED AT THE TECHNICAL MEETING AND WILL BE CONSIDERED FOR PUBLICATION IN CIM JOURNALS IF FILED IN WRITING WITH THE TECHNICAL PROGRAM CHAIRMAN PRIOR TO THE CONCLUSION OF THE MEETING.

ABSTRACT

Between October 1980 and February 1981, Texaco Canada Resources Ltd. drilled three horizontal holes in soft, shallow, unconsolidated Athabasca Tar Sands at their Fort McMurray Pilot Plant, Alberta, Canada.

Objectives of the project were to produce bitumen at very shallow depths with minimum drilling cost, lease cost and environmental impact. The accomplishment is believed unique in that all three wells were drilled from the same drilling pad, each well being spudded in at a vertical angle of 45°, and a horizontal attitude was achieved at a true vertical depth from surface of approximately 125 m (410 ft.). Over 350 m (1,000 ft.) of horizontal hole was drilled to complete each well.

A new, innovative, hydraulically operated drilling rig was built for this project with a 110,000 kg. (240,000 lb.) hoist and 22,700 kg (50,000 lb.) push-down capacity. New techniques were developed to drill enlarge and underream the horizontal hole up to 368.3 mm (14 1/2") diameter. Mud motors were used to power the bit and the force on the bit was accomplished by pushing down on the drill pipe.

INTRODUCTION

Texaco Canada Resources Ltd.'s Fort McMurray Pilot Project is in the Athabasca Tar Sands deposits and located 19 km southeast of the city of Fort McMurray (Figure 1). The bitumen from these deposits is extremely viscous with a pour point in the order of 21°C (70°F). Typical properties of the bitumen are:

Gravity API: 7° - 9°
Specific Gravity at 15°C: 1.007
Nature at ground temp. of 7°C: Solid
Viscosity at 205°C: 10 CP
Carbon Content: 81.8%
Sulphur: 5.3%

The deposits vary in thickness from stringers to over 60 m (200 ft.). The overburden ranges from surface exposure to in excess of 550 m (1800 ft.). Approximately 10% of this tar sand is considered to be strip mineable, so that many companies operating in the Athabasca area have concentrated on experimental in-situ methods of recovery.

At Texaco's McMurray lease, the tar sands are approximately 45 m (150 ft.) thick but comprise a heterogenous layered mixture of bitumen, sand and clay with occasional hard shale stringers. While the pore space is partially gas and water saturated, there is no initial formation pressure. The overburden is 76 m (250 ft.) thick and consists of the Clearwater formation shales, sands, and sandstone stringers, covered by soft glacial till containing gravel and rock boulders. The surface is made up of muskeg with shallow lakes, interspersed by dry, higher ridges. Core hole drilling is normally done in the winter months when the muskeg is frozen solid as the terrain is largely impassable for the rest of the year. For continuous operations, one to two meters of clay fill are packed over the muskeg for roads and drilling and production pads.

Texaco has operated an experimental steam flood using vertical wells on its McMurray lease since 1972. The initial Pattern I was a 4 hectare (10 acre) 9-spot with central injection while the next Pattern II started in 1976 was a 1.2 hectare (3.75 acres) enclosed 7-spot with central and peripheral steam injection. Over 500,000 bbls. have been recovered to date from these two patterns with indicated recoveries approaching 100,000 bbls./acre from Pattern II. However, economic analyses indicated that further improvements would be required to provide for acceptable recovery of capital and operating costs.

The use of long horizontal drain-holes appeared to be the best way of reducing capital costs while providing for improved recovery. Since the flow capacity of wells is generally proportional to the pay thickness, a 300 metre (1,000 ft.) horizontal well bore could replace 7 vertical wells. This provides a significant reduction in the required roads, drilling pads, steam and flowlines, and associated manifold and test facilities. In addition, the environmental impact of development is greatly reduced. If the horizontal well bore is located near the base of the sand, improved performance may be expected due to gravity effects in the reservoir.

In 1979, the Company initiated a program to drill three long horizontal wells at the McMurray Pilot from a single drilling pad. This required a drilling rig capable of operating at unusual off-vertical angles, a pushdown capability to apply force to the bit in the horizontal hole, adequate pump capacity to run down-hole hydraulic motors for directional drilling and a large power swivel for drill-string rotation when required.

At that time, no rig was known to exist which would meet these requirements, which amounted to an oil well drilling rig with mine boring adaptations. Enquiries to drilling contractors in Alberta resulted in Texaco Canada Resources Ltd. entering into a contract with Westburne Drilling (Canada) Ltd. to provide and operate a custom rig to be made by E.A. Kutryk Industries Ltd. of Calgary, with a specification listed in Table 1. This rig was operated hydraulically for both pulling up, pushing down and rotating the drill pipe. Conventional blocks and wireline were not used, a conventional power swivel on a hydraulic-ram motivated trolly, sliding up and down the mast, being the connection to the drill pipe. Because of anticipated difficulties in handling normal drill pipe tongs at 45°, a hydraulically powered spinning and torque wrench was incorporated into the mast structure for making and breaking pipe joints. Figure 2 shows some aspects of the rig.

The remainder of the rig, including the drilling mud circulating system, followed conventional practice. The substructure height of 4.6 m (15 ft.) allowed use of a complete blowout preventor stack.

DRILLING CONSIDERATIONS

In designing the drilling program, the following factors were kept in mind.

1. All three wells would be drilled from one drill pad with wellheads 9 m (30 ft.) apart.
2. The horizontal portions of each hole were to be drilled at 125 m (410 ft.) depth, and spaced 125 m (410 ft.) and 75 m (246 ft.) apart.
3. A maximum change of angle rate of 5°/30 m (5°/100 ft.) was specified to minimize tubular stress and reduce pipe drag.
4. The glacial till is very soft, while the tar sands consist of loose sand bonded by bitumen.
5. Wells would be used both for injection of steam, etc., and production of bitumen.
6. As sticking of casing/liner was possible, while being run, sizes should be such that a smaller diameter liner could be run through the first liner if it became stuck before reaching total depth.
7. The mud system would have to power the mud motors, provide maximum friction reduction for oil well tubulars and clean the hole effectively.
8. Force on the bit had to be provided by pushing down on the drill string.
9. Continuous read out of direction and inclination of hole would help to ensure the hole remained on the desired course.
10. Design temperatures for casing and tubing to be saturated steam at 2165 kPa (314 psia) equivalent to 216°C (421°F).
11. To obtain information on downhole temperatures, during injection and producing operations, thermocouple strings would be run if possible.

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To accomplish the objectives and meet the above considerations, the following drilling program was prepared. (All depths are as drilled, unless noted at True Vertical Depth (TVD), the latter being the vertical depth from surface.)

1. Preset, by pile driving, approximately 20 m of 508 mm (20 in.) 139.6 kg/m, 11 mm wall, grade H-40, buttweld pipe as conductor, at an angle of 45°.
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3. Ream hole to 375 mm (14 3/4") with hole opener.
4. Run 130 m, 273 mm (10 3/4") 82.6 kg/m, MN 80 BTC, API casing with special centralizers designed to impart a swirl to cement.
5. Cement with oilwell thermal cement.
6. Displace old drilling mud to polymer mud, with lubricant additives.
7. Drill from 130 m (94 m TVD) to 300 m (120 m TVD) building angle at 5° per 30 m with 245 mm (9 7/8") bit to achieve an angle of approximately 90°. All drilling to be with mud motor and using steering tool.
8. Drill ahead with 245 mm bit to achieve as much horizontal hole as possible (Target: 300 m).

9. Run in liner consisting of approximately 480 m, 193.7 mm (7 5/8") 50.15 kg/m, MN 80 BTC API casing slotted with 0.030 slots. Land liner packer to approximately 120 m with liner shoe 1 m above bottom of hole.

10. Run 450 m, 114 m (4 1/2") 22.5 mg/m, N80, 8 RD LT & C, API casing, as tubing string, with thermocouple string, pre-installed in 25.4 mm endless tubing and strapped to 114 mm tubing, the shoe to be approximately half way down the slotted section of the 193.7 mm liner.

11. Install wellhead and thermocouple connections.

The plan for these wells is shown in Figure 3. To ensure that the mud temperature would not exceed 18°C (65°F), a mud chilling system was installed. A slip-stream from the mud tank could be directed through the chiller of a refrigeration system, as required.

The polymer mud system chosen gave maximum lubrication while meeting all other conditions. An oil-base mud would have given better conditions for running casing, but at low mud temperatures, the viscosity would have been unacceptably high and would have created extremely high pump pressures.

OPERATING DATA

Figures 4,5,7 and 9 show the drilled path of the holes while figures 6,8, and 10 show drilling progress on a time basis for both true vertical depth and measured (drilled) hole depth.

The 300 m target for the horizontal portion of the hole was achieved in all cases, although the path to the target was not exactly as planned. A time analysis of the three holes shows that while the first hole, H-1, was delayed by 6 days for rig repairs and modifications, 18 days were lost while drilling hole H-3 because of bad hole conditions resulting in tight hole and stuck pipe.

COMPLETION

Figure 11 shows the completion of hole H-3 which is typical for all three horizontal holes. Both the 273 mm (10 3/4") casing and 194 mm (7 5/8") liner were grade N80 API with buttress threaded collars to withstand thermal expansion without exceeding yield strength.

The surface casing is cemented with a thermal cement containing 40% silica flour. The liner has slots over the horizontal portion only of the hole and is not gravel packed. The packer at the top of the liner does not have slips in order that initial thermal expansion will not be restrained.

The tubing is a string of 114 mm (1 1/2") N80, API 8RD thread casing joints. The pump seating nipple (PSN) is provided for a downhole pump and the slotted section below the PSN is intended to give more even distribution of steam during the injection phase of operations. The choice of 114 mm tubing sizes inside the 194 mm liner, is to give theoretical minimum pressure drop to steam injected down both tubing and annulus.

Not shown in Figure 11 is the 25.4 mm (1 in.) endless tubing which contains the thermocouples for well temperature observation and which is anchored to the shoe of the 114 mm tubing.

EQUIPMENT PERFORMANCE

(a) Drilling Rig

It was found that a disproportionate amount of the total time to drill these horizontal holes was taken by running drilling assemblies in and out of the hole. The rig was designed to pick up and lay down drill pipe by single joints only and a good pipe handling system is very necessary. Equipment and techniques to handle the pipe were steadily developed and are now at an acceptable level.

The hydraulic system for pulling up, pushing down and rotating the drill pipe proved satisfactory after initial problems were overcome, even when temperatures were as low as -36°C (-30°F).

(b) Downhole Tools

The angle build-up drilling assembly consisted of a 245 mm (9 5/8") long-tooth rock bit, powered by 6 1/2" Dynadrill and Navidrill mud motors with a bent sub to give the necessary "kick". Various bent subs with angles ranging from 1/2° to 4° were available. This assembly was used for drilling all holes, including the horizontal drilling assembly to counteract any tendency to drop off.

Above the drilling assembly, three non-magnetic drill collars were run for directional surveys. This number was a minimum to reduce magnetic interference in very high angle surveys, to negligible proportions. Heavy weight drill pipe 114 mm (4 1/2") 61 kg/m (41 lb./ft.) was used to surface. This provided a stiffer than normal drill string between bit and surface push down force to give better directional control. In the third hole, H-3, some normal weight 114 mm drill pipe was successfully used in the horizontal section to reduce drill string drag, and allow drilling further with the same push down force.

No problems in building up angle were encountered, even in the very soft formations. The actual force on the bit could not be measured due to hole drag, but the very soft formation required only a light force.

Hole opening was accomplished by rotating the drill pipe with a blade hole opener on bottom. The nose of the opener mounted a non-rotating 245 mm (9 5/8") stabilizer which readily followed the original hole with no tendency being detected to bury itself, and start a new hole.

(c) Directional Surveys

Accurate knowledge of the location of hole and direction of progress at any time was vital to the successful drilling of these wells. A steering tool was used at all times while drilling. Located in the non-magnetic drill collar string and connected to surface by wireline, this tool provided constant surface digital data on hole inclination and azimuth. The tool generally worked well, but the necessary wireline caused considerable inconvenience. Also, the tool has to be located so that a non-magnetic drill collar is between the tool and mud motor/bit, which means that information is some 15 m (50 ft.) late. Careful attention to directional trends is required.

To confirm steering tool directional information, multi-shot surveys were run. Reasonable correlation was obtained.

(d) Mud System

Use of a simple aquagel/bentonite mud to the top of tar sands, and a polymer mud within the tar sands, proved satisfactory. Desanders and a centrifuge mud cleaning system were necessary at all times to keep solids to a minimum and reduce wear on the mud motors. Ambient temperatures were low enough that the chilling system was not required. However, an inadvertant heating of the mud system on one occasion, quickly resulted in sticky hole conditions, confirming that higher ambient temperatures would have required use of the mud chilling system.

HOLE PROBLEMS

(a) Wash Out Below Surface Casing

This was encountered on holes H-2 and H-3 and, is believed, due to the pile-driven conductor shoe being in a soft clay formation. The wash out resulted in difficulty in re-entering into previously drilled hole and was overcome only by repeated cement plugging and redrilling.

(b) Tight Hole

In the third hole, H-3, tight spots were encountered, due to swelling bentonitic clays and/or tar with low sand content gradually flowing into the hole. This resulted in repeated reaming while drilling, and difficulties in running the liner.

(c) Hole Drag

Hole drag was such that, with heavy weight drill pipe, and the mud system used, the rig capability was no more than 600 m (1968 ft.). Substitution of standard drill pipe for some of the heavier pipe in the horizontal section noticeably reduced drag and allowed hole H-3 to be drilled to 629 m (2064 ft.). In all cases, it was found necessary to augment the 22,750 kg (50,000 lb.) rig push down with drill collars at the top of the string to speed up running in of pipe into the hole and obtain sufficient force on bit for drilling ahead.

(d) Running Liner

The increased surface area and light weight of the 194 mm (7 5/8") liner resulted in extremely slow running time. For example, in hole H-1, 32 hours were required. On hole H-3, the above-noted tight spots resulted in the liner parting at 170 m (558 ft.) while attempting to work the liner into the hole. The portion left in the hole was successfully fished out. To run the liner in this hole, horizontal underreaming of the hole to 368 mm (14 1/2"), and a means of circulating the liner while running in, were successfully developed.

COSTS

The cost of these first horizontal holes were 5 to 6 times that of a vertical hole. In terms of sand exposure, the equivalent of more than seven vertical holes were drilled in an average horizontal hole. These relative costs reflect the experimental nature of the project using new, unproven equipment, the necessity to modify conventional equipment, and develop new drilling techniques, together with time necessary to train people in this horizontal hole concept. It may be expected that, with modifications and development of equipment, and with further experience, that the costs would be significantly reduced.

FUTURE IMPROVEMENTS

Expansion of in-situ recovery methods in the Athabasca Tar Sands to the commercial stage will require further development and improvement of horizontal hole equipment and techniques. The following merely list items for further improvements.

1. Pipe handling equipment, to reduce rig time.
2. Increased push-down capability, to reduce use of drill collars.
3. Extension of the rig range by using lighter drill tubulars and mud lubricants.
4. Development of completion techniques with regard to liners, gravel packing and tubing.
5. The bit direction control and monitoring read out systems to reduce tripping of the assembly.

SUMMARY

Drilling this pattern of 3 horizontal holes in very shallow, unconsolidated tar sands for in-situ recovery of bitumen by thermal processes is believed to be unique. The objectives were all achieved, though not without unforeseen difficulties and additional costs. New drilling techniques and equipment were successfully developed so that the drilling of similar holes in future tar sands projects can be considered a viable alternate to conventional, vertical holes.

Perhaps the biggest problem overcome by those most closely associated with the project is an adjustment to thinking horizontal. Such a well is not a vertical one on its side.

ACKNOWLEDGEMENTS

The author wishes to thank Texaco Canada Resources Ltd. for permission to publish this paper which was prepared for, and presented at, the 2nd International Conference on Heavy Crude and Tar Sands at Caracas, Venezuela, February 7 to 17, 1982. The assistance given by fellow workers in the Oil Sands Group of the Company, especially Messrs. D.C. Loxam and I.E. Varga, also that of E.A. Kutryk Industries Ltd. and Westburne Drilling (Canada) Ltd. is most appreciated.

TABLE 1

KUTRYK KS-1 HYDRAULIC
SLANT-HOLE RIG

KB to Ground
At 0° - 3.95 m
At 45°- 5.55 m

Bottom of Table Beam to Ground
At 0° - 3.65 m
At 45° - 5.10 m

Hydraulic System:	34,000 kPa skid mounted.
Max. Lifting Capacity:	110,000 daN w/450 kW to ram.
Max. Hoisting Travel:	13.70 m.
Max. Hoisting Speed:	10 sec. per single.
Hoisting Speed @ Full Load:	35 sec. per single.
Prime Movers:	2 GM 6-71 'N' Series Twin sets.
Mast:	Kutryk 16.75 m single section w/175,000 daN capacity.
Max. Angle:	0° to 45° in 5° increments.
Substructure:	Box type 3.95 m H x 5.50 m L x 3.65 m W.
[illegible]wer Swivel:	Bowen S3.5 track mounted in derrick w/attachments for casing elevators. Provides 850 daN/m torque @ 150 rpm.
Pump:	National K-500-A w/Hydril K-20-3000 pulsation dampner.
Pump Power:	2 - GM 8V-71 'N' Series w/12V-71 radiators and Allison 855 torque converters.
Mud System:	Unitized skid mounted w/3 compartments complete w/GM powered low pressure system for mixing and/or agitation and fitted w/high pressure roll for mixing and/or agitation. 45 m^3 capacity.
Shaker:	2.25 kW Link Belt NRM 145 w/1.21 m x 1.52 m screens.
Water Tank:	45 m^3 capacity, mounted on skid w/toolhouse. Features drop in doghouse.
Toolhouse:	On skid w/water tank/doghouse unit. 4 m L x 3.04 m W and includes oil storage.
Power Plant:	2 - Cat 315 engines w/30 kW generators. Housed in combination building with accumulator and change house.

FIG. 1

OIL SANDS OF ALBERTA

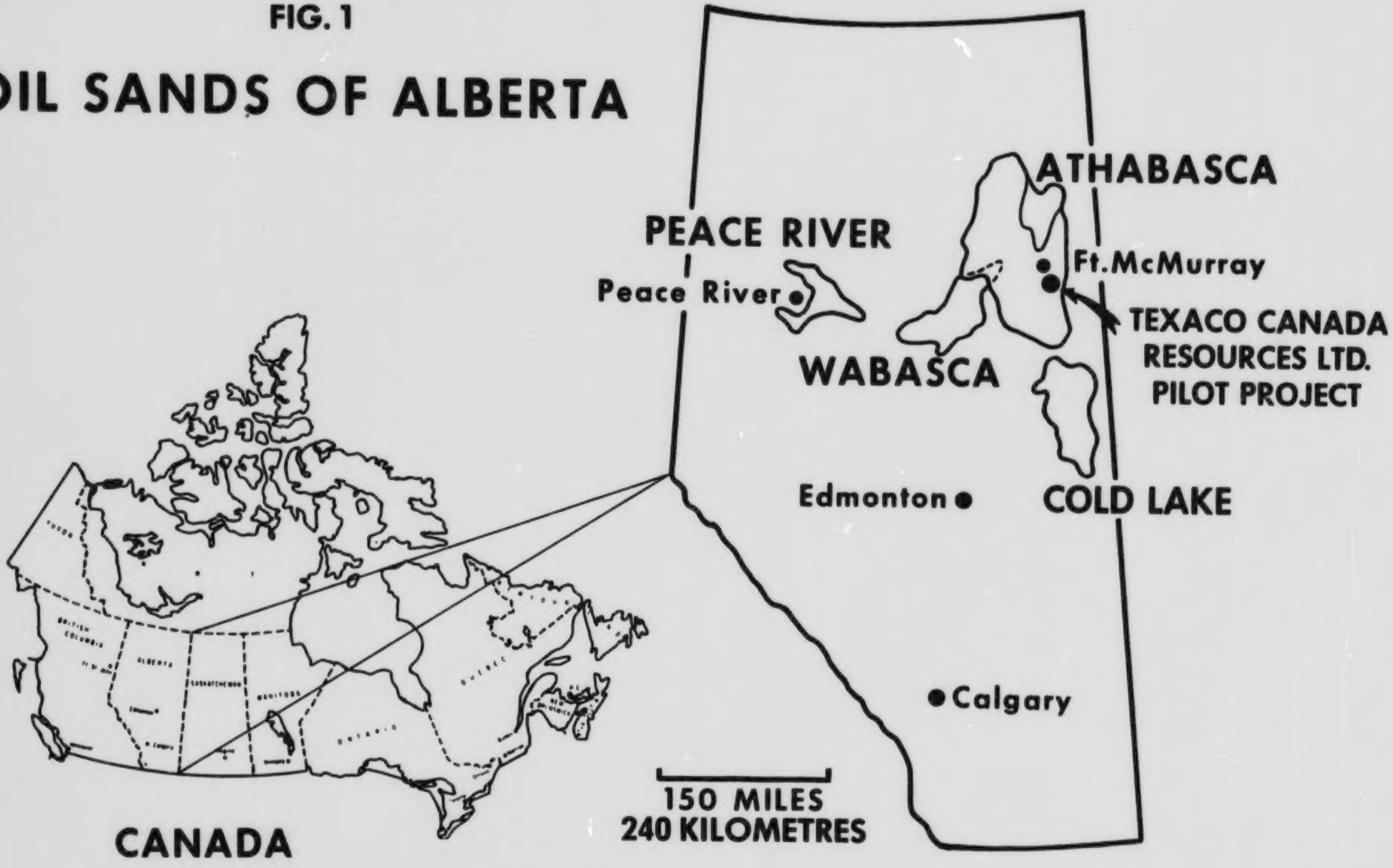
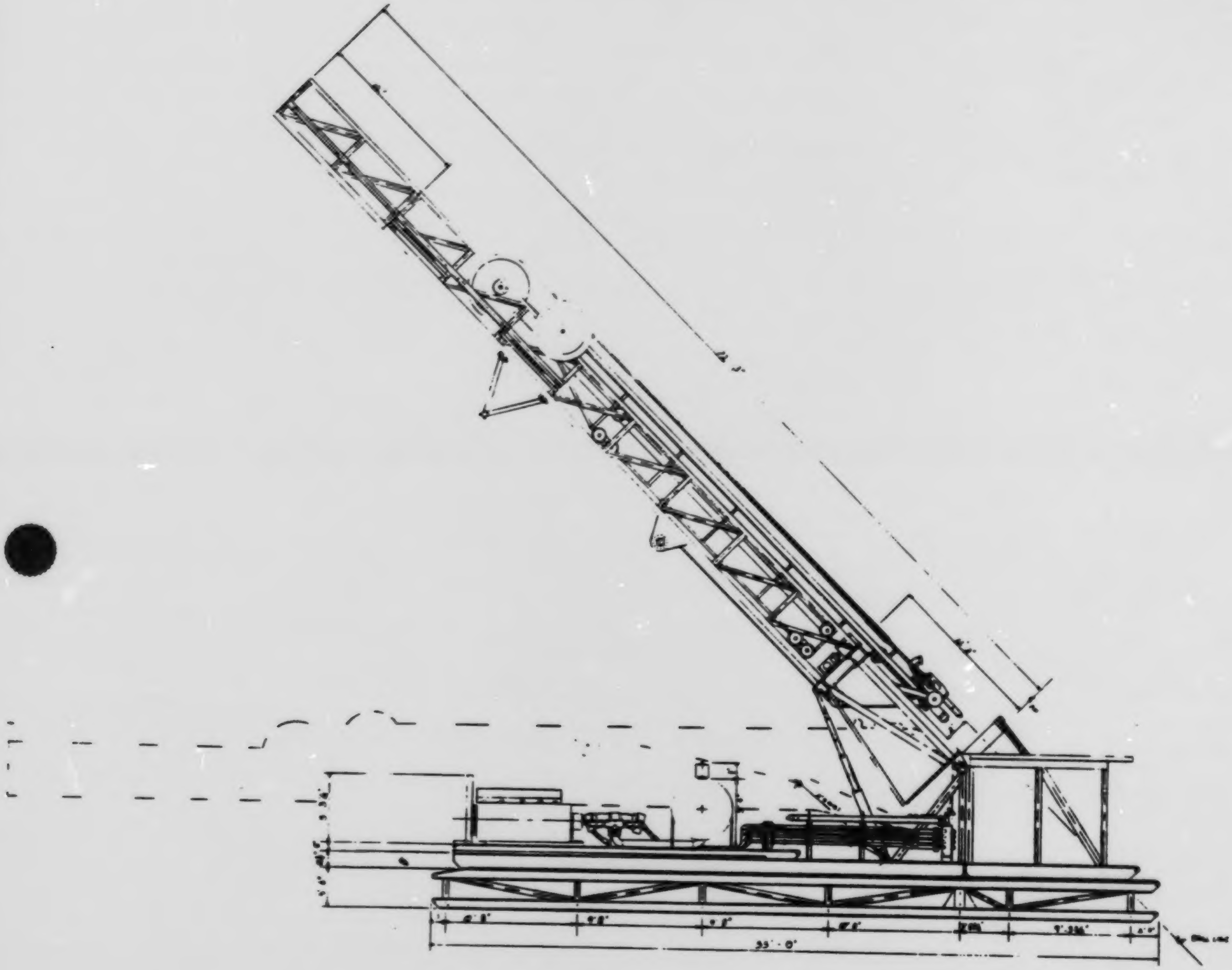

ATHABASCA
PEACE RIVER
Ft.McMurray
Peace River
TEXACO CANADA
RESOURCES LTD.
PILOT PROJECT
WABASCA
Edmonton
COLD LAKE
Calgary
150 MILES
240 KILOMETRES
CANADA

FIG. 2

Westburne Drilling (Canada) Ltd.
Rig #30



KS-1 SLANT HOLE HYDRAULIC DRILLING RIG

E.A. KUTRYK INDUSTRIES LTD
CALGARY, ALBERTA, CANADA

Westburne Drilling
(Canada) Limited

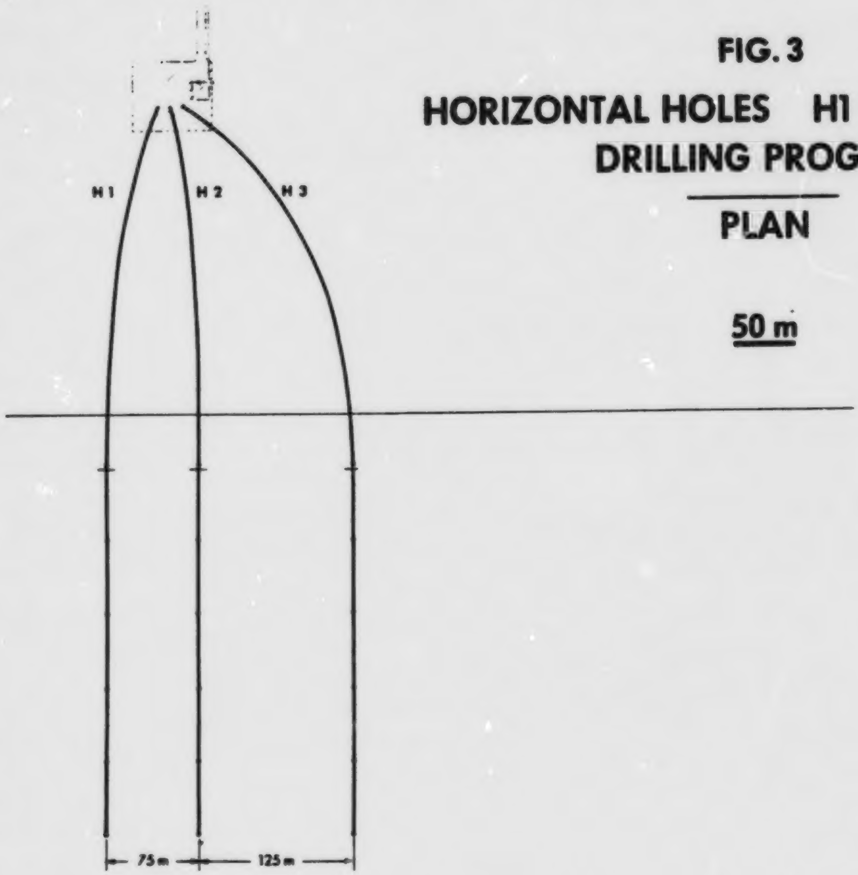
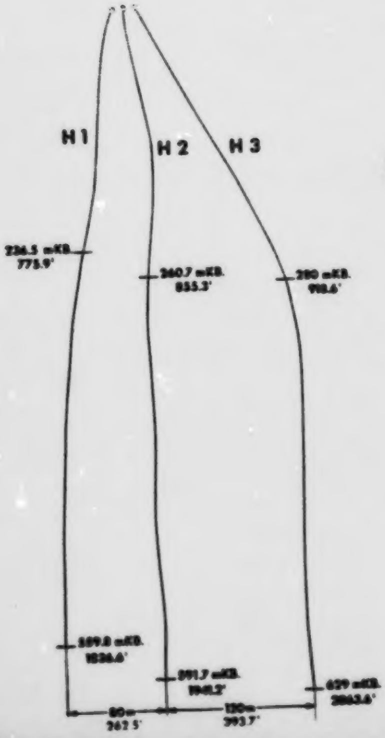

H 1
H 2
H 3
75 m
125 m

FIG. 3

HORIZONTAL HOLES H1 H2 AND H3 D
DRILLING PROGRAM

PLAN

50 m


H 1
H 2
H 3
236.5 mKB.
775.9'
260.7 mKB.
855.3'
280 mKB.
918.6'
559.8 mKB.
1836.6'
591.7 mKB.
1941.2'
629 mKB.
2063.6'
80m
262.5'
120m
393.7'

50 m

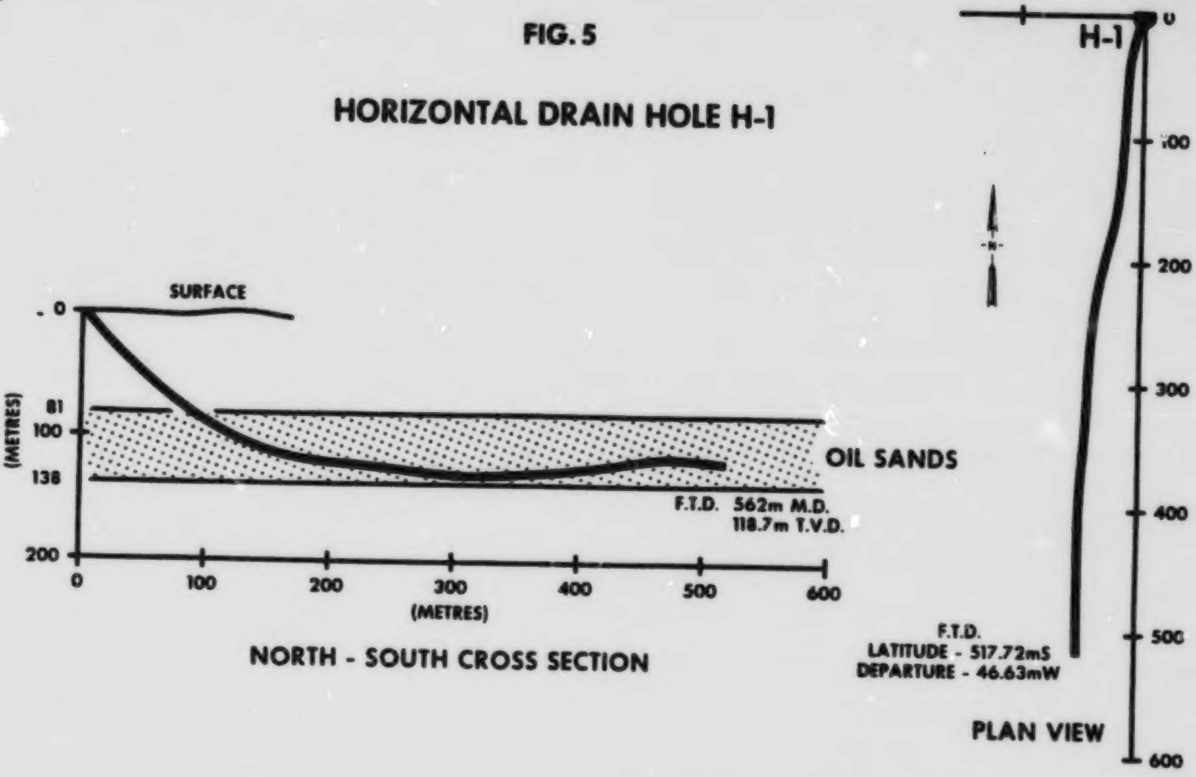
FIG. 4

ATHABASCA PILOT PROJECT
HORIZONTAL HOLES AS DRILLED

CONFINED 6.2 ha (15.4 ACRES)

FIG. 5

HORIZONTAL DRAIN HOLE H-1



NORTH - SOUTH CROSS SECTION

PLAN VIEW

FIG. 6

H-1 DEPTH VS DAYS

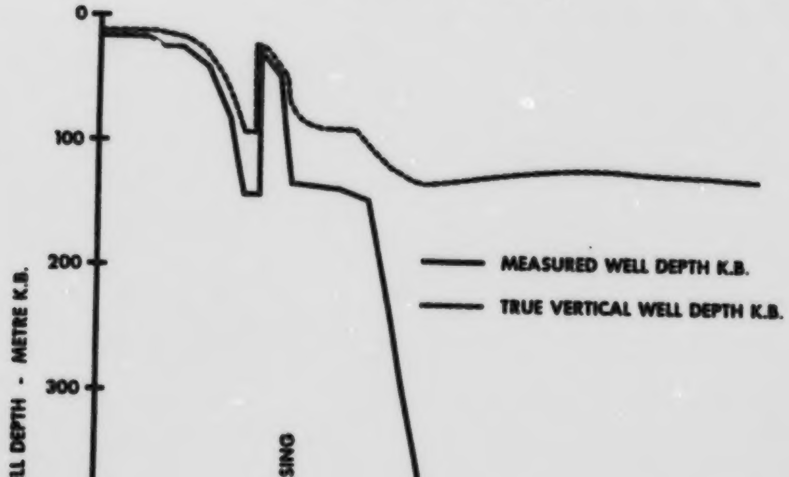
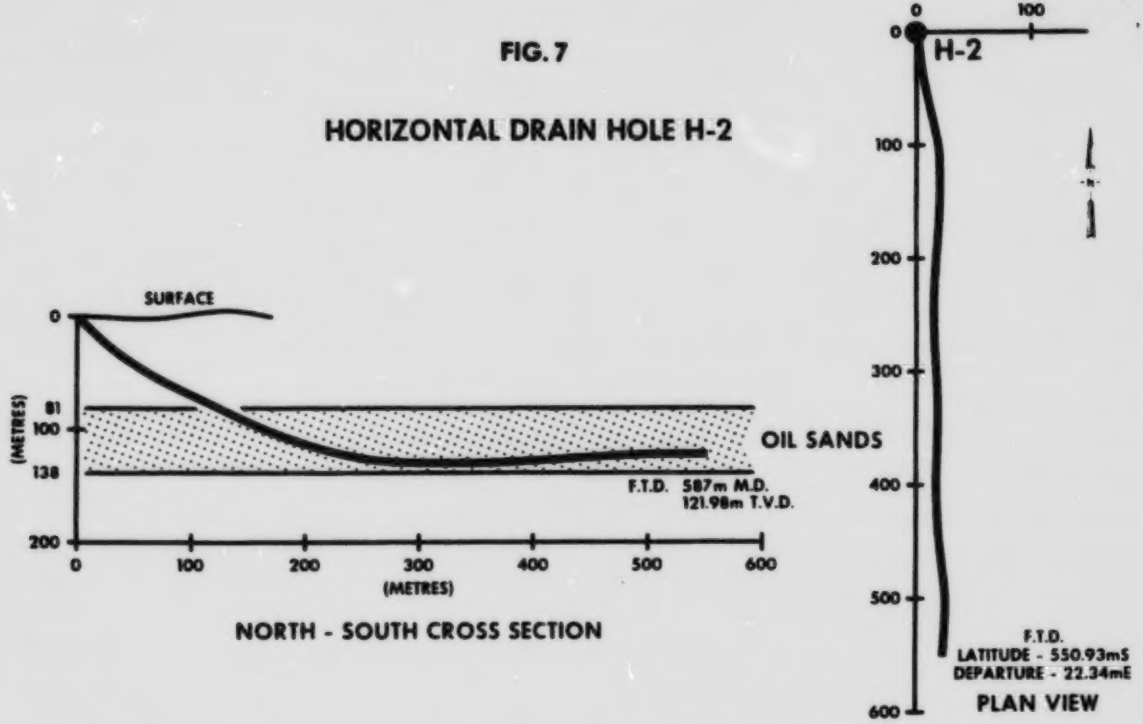


FIG. 7

HORIZONTAL DRAIN HOLE H-2



NORTH - SOUTH CROSS SECTION

PLAN VIEW

FIG. 8

H-2 DEPTH VS DAYS

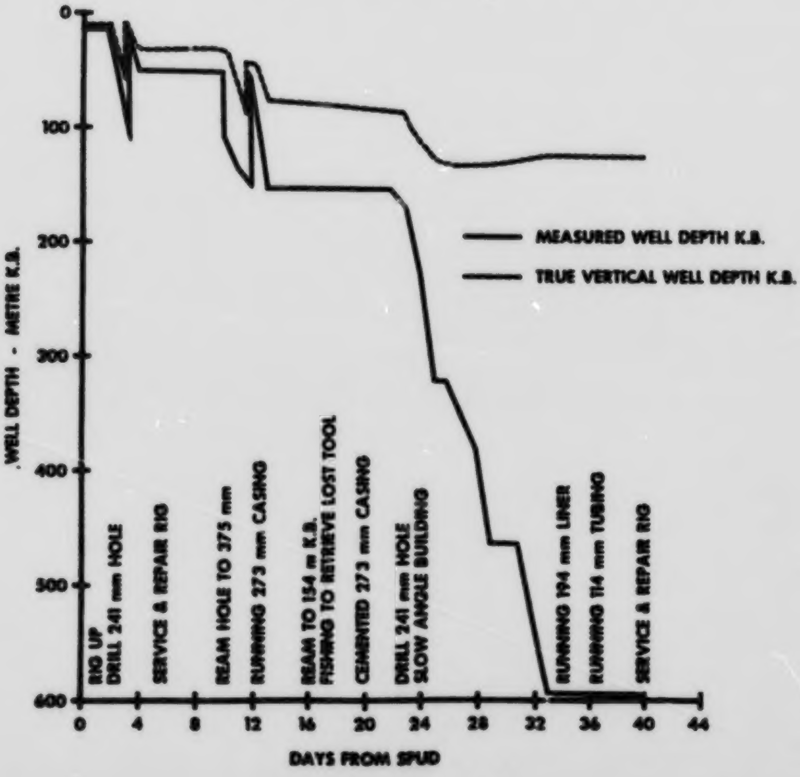
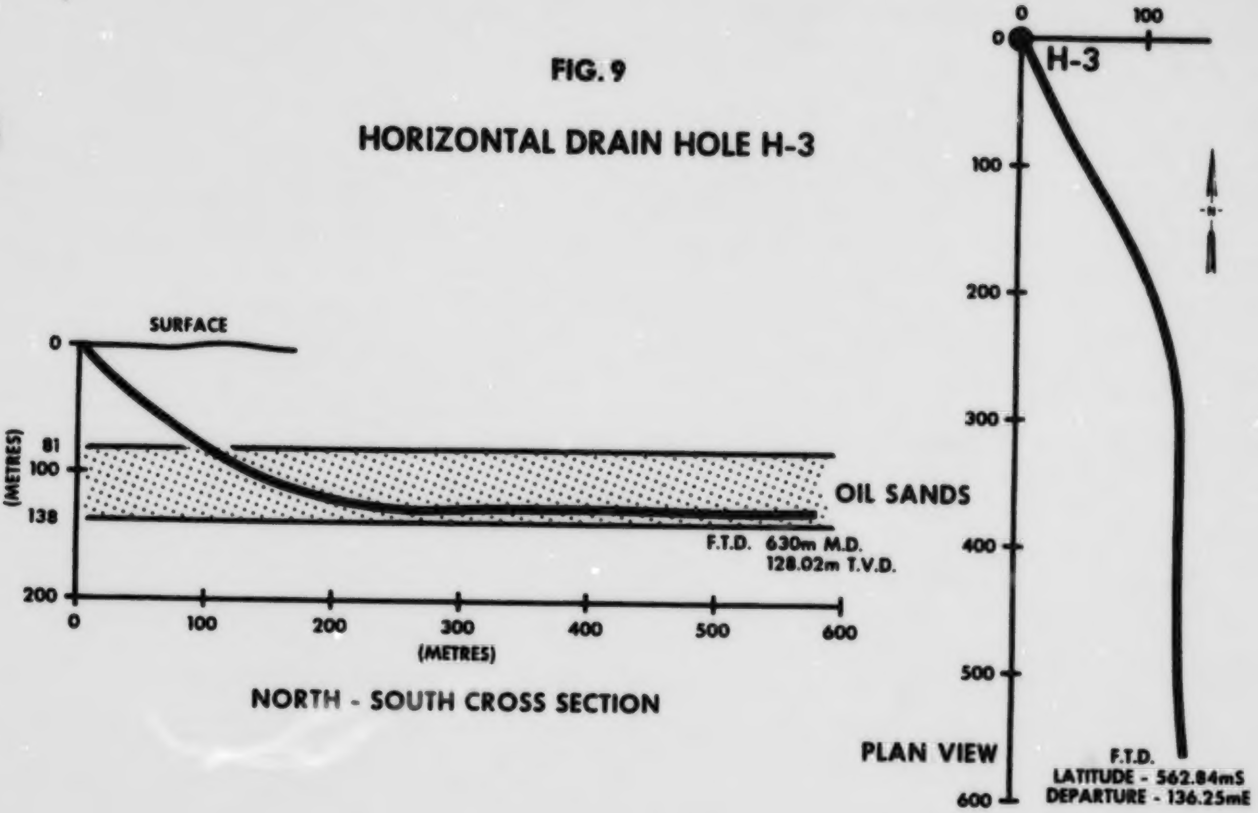


FIG. 9

HORIZONTAL DRAIN HOLE H-3



SURFACE
0
81
100
138
200
(METRES)
OIL SANDS
F.T.D. 630m M.D.
128.02m T.V.D.
0
100
200
300
400
500
600
(METRES)
H-3
0
100
200
300
400
500
600
N
F.T.D.
LATITUDE - 562.84mS
DEPARTURE - 136.25mE

NORTH - SOUTH CROSS SECTION

PLAN VIEW

FIG. 10

H-3 DEPTH VS DAYS

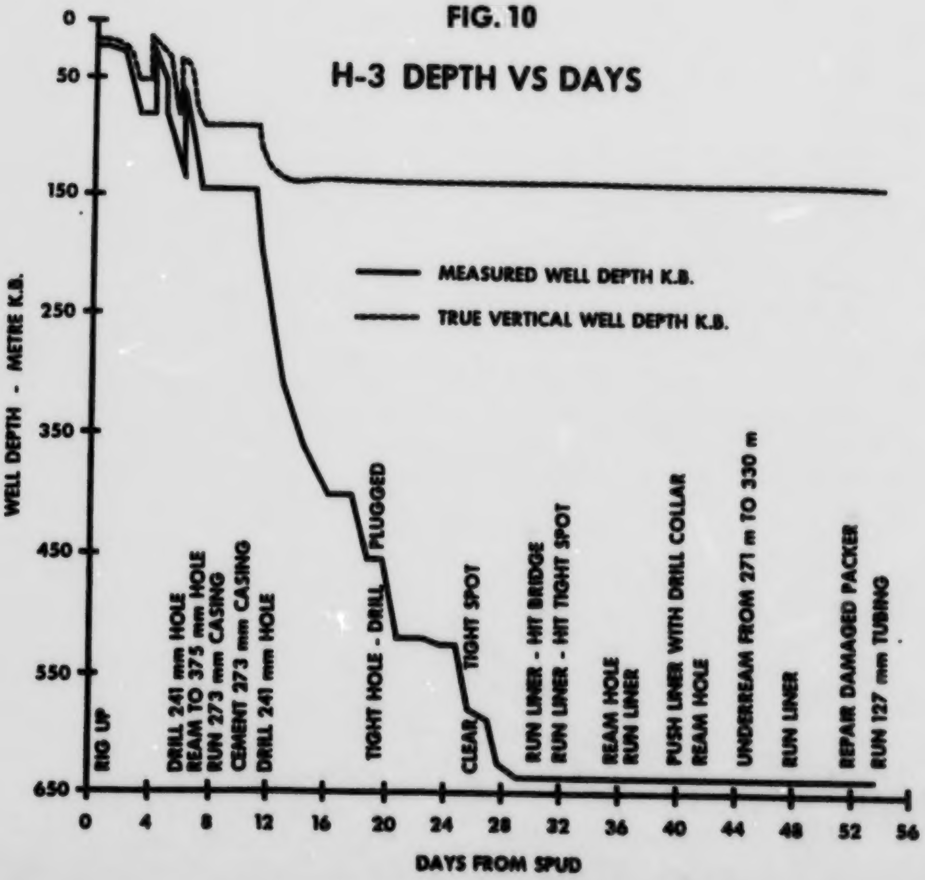
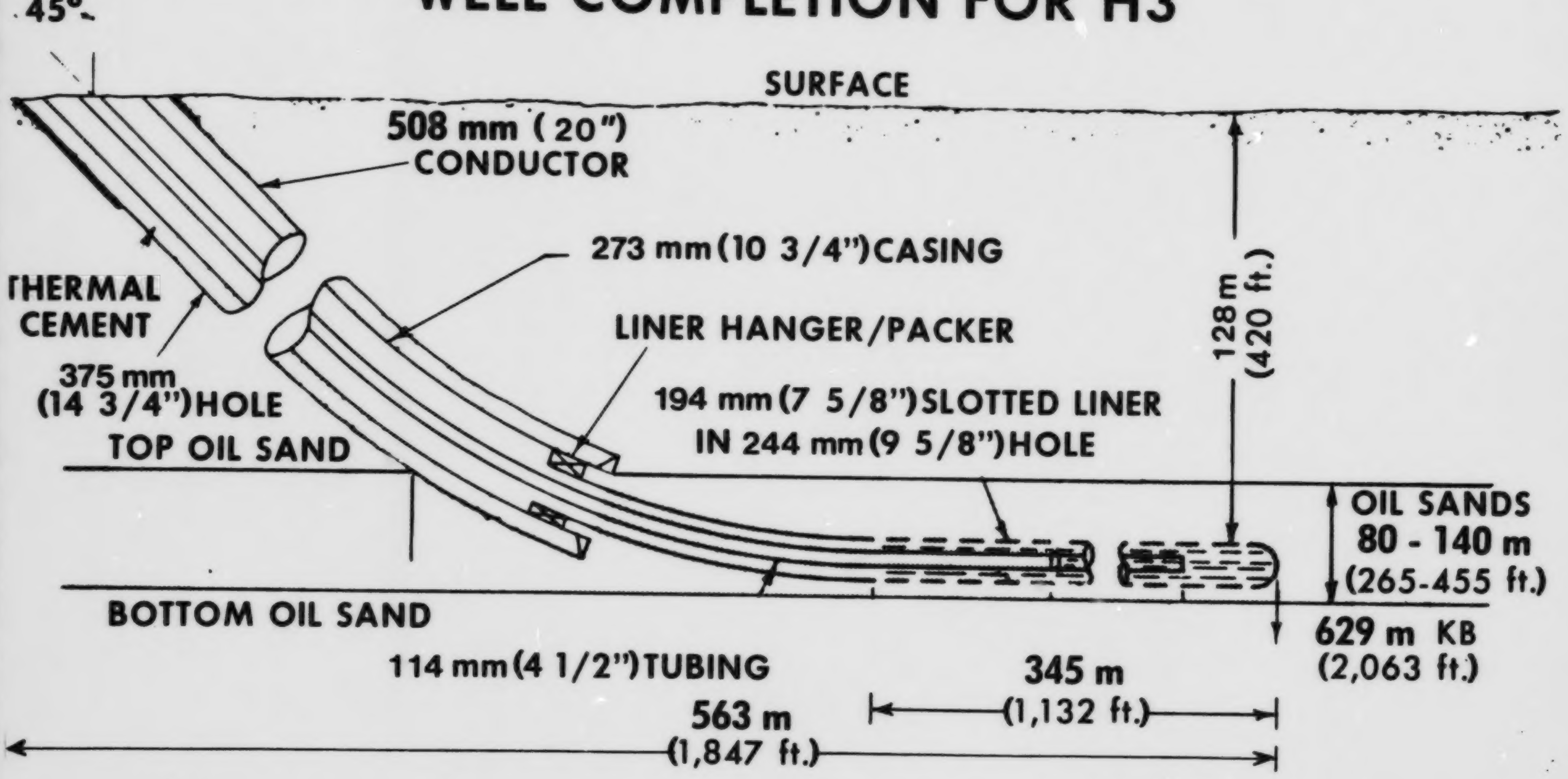


FIG. 11

ATHABASCA PILOT PROJECT
PATTERN III

WELL COMPLETION FOR H3



45°
SURFACE
508 mm (20") CONDUCTOR
273 mm (10 3/4") CASING
THERMAL CEMENT
LINER HANGER/PACKER
375 mm (14 3/4") HOLE
194 mm (7 5/8") SLOTTED LINER IN 244 mm (9 5/8") HOLE
TOP OIL SAND
128 m (420 ft.)
OIL SANDS 80 - 140 m (265-455 ft.)
BOTTOM OIL SAND
629 m KB (2,063 ft.)
114 mm (4 1/2") TUBING
345 m (1,132 ft.)
563 m (1,847 ft.)

009431
Alberta OIL SANDS
INFORMATION CENTRE

(18)

HEAVY OIL & OIL SANDS TECHNICAL SYMPOSIUM

"Challenges and Innovations 1984"

FEBRUARY 16, 1984

Presented by the
Faculty of Continuing
Education

THE UNIVERSITY OF CALGARY

TEXACO CANADA COMPLETES

A UNIQUE HORIZONTAL DRILLING PROGRAM

Presented by

D.C. Loxam
Assistant Superintendent
Operations - Oil Sands Division

February 16, 1984

Texaco Canada Resources Limited has operated an in situ pilot project south and east of Fort McMurray since 1972. By 1979, the company realized the shallow oil sands could be developed by drilling highly deviated wells, however, the combination of shallow depth and unconsolidated bituminous sands presented unique drilling problems to obtain long horizontal sections. This situation evolved a drilling rig with a 45 degree slanted mast (Figure 1), (Picture 1).

The Rig

Texaco contracted Westburne Drilling (Canada) Ltd. of Calgary to build the unique rig. Westburne teamed up with E.A. Kutryk Industries Ltd. of Calgary to design and build the hydraulic slant drilling rig (Figure 2), (Picture 2), (Table 1).

Although the wells were shallow, pipe drag during lifting and lowering operations would be significant. A lifting capability of 100,000 dN was required to lift a drill string or liner off bottom. Conversely a push down capability of 22,200 dN was required to obtain force on a bit or to push a liner to bottom as only 70% of the string weight, drill collars (D.C.) and heavy weight drilling pipe (H.W.D.P.) was applied down the drill string at 45 degrees. The force from string w eight rapidly declines as the angle increases.

The rig hydraulically raises, lowers, and rotates the tubulars. An upper moveable mast section is fixed to a large hydraulic cylinder and is supported in a stationary lower mast section. This provides pipe raising and lowering capability through a cable system, tied to a power swivel cart, strung up and over large sheeves on top of the moveable mast and anchored to the base of the stationary mast. This arrangement provides a 2 to 1 travel ratio for the cable to the cylinder movement.

A Bowen power swivel, mounted on the cart, travelling in a track assembly on the moveable mast, provides rotary power and a direct connection to the tubulars. Conventional blocks and bails were not used.

A Varco iron roughneck was used for heavy connection make up. The remainder of the rig followed conventional practices.

Drilling Operations

Texaco drilled the three horizontal wells from a single pad. The wells have an average of 334 m of horizontal section at an average of 126 m true vertical depth (T.V.D.). The averaged drilled depth per well was 597 m with the horizontal sections spaced 75 m and 124 m apart respectively. Figures 3 and 4 show planned and actual programs for the wells. Drilling time averaged 46 days per well. (Figures 5 through 10).

The three wells had 15 m of predriven 508 mm conductor pipe set at 45 degrees to the vertical and orientated to give the required azimuth angle for the completion.

Each well was directionally drilled with a 241 mm pilot hole, with angle build-up at 5 degrees/30 m from the conductor pipe to the top of the oil sands at approximately 127 m drilled depth (D.D.). T.V.D. was 80 m at an angle of 54 degrees from the vertical. Drilling was by mud motor.

The pilot hole was reamed conventionally to 375 mm and a 273 mm, 81.98 kg/m Buttress MN80 seamless casing was run, set at 130 m total depth (T.D.) and cemented with thermal type cement. Drilling continued using 241 mm bits powered by mud drilled motors, with angle build up at 5 degrees/30 m to 300 m D.D. (120 m T.V.D.) where 90 degrees was achieved, and to T.D. with altered assemblies to counter the effect of gravity on the drill string.

A 194 mm, 49.98 kg/m Buttress MN80 seamless liner was run and set with blank pipe from the casing landing depth to the start of the horizontal section and with slotted liner (10,000 mm/m of 0.76 mm slot) to T.D. The liner was not cemented.

A string of 114 mm, 22.5 kg/m tubing was run to T.D. for logging and then changed to a completion string. A thermal couple string, preinstalled in a 25.4 mm endless tubing was strapped to the 114 mm tubing string and both landed approximately half way down the slotted liner section. The well was circulated to fresh water and the wellhead installed (Figure 11), (Picture 3).

Drill String Assemblies

Mud motors, Dynadrill or Navidrill, powering long tooth soft formation bits, were used to continuously drill and build angle at 5 degrees/30 m with good penetration rates and bit life. Various bent sub assemblies were used with both types of motors to achieve the required angle buildup. Bent housing drills were also used with and without bent subs to stay on track. Stabilizers were used to maintain hole trajectory.

Monel drill collars were run behind the drills to reduce magnetic interference on the survey tools. H.W.D.P. with D.C. was used above the drill assemblies to add weight and provide a stiff assembly for surface push down. Light weight drill pipe (L.W.D.P.) was used in the third well horizontal section to obtain maximum weight benefit as the rig push down capability was insufficient to obtain the desired drill rate and penetration.

Conventional rotary drilling was used to ream for production casing. A non-rotating stabilizer preceeded the hole opener to prevent drift. Rotary drilling was also used to underream a tight hole in the third well to run the liner.

Directional Surveying and Control

The target of 300 m of horizontal section for each well was achieved and deviation control improved each time. A steering tool located in the non-magnetic drill collars and connected to surface by wireline was used at all times while drilling. This provided constant surface digital data on hole azimuth and inclination. Multishot surveys were run with good correlation to steering tool data.

Mud System

An aquagel-bentonite system was used to drill to the top of the sands and a polymer system was used to drill through the sands. The polymer system was to prevent clay swelling and tar sticking in the well. A desander and centrifuge were used at all times to keep solids to a minimum in the system and thus reduce motor wear and weight build up.

A chiller unit was installed in the mud system to maintain low circulating temperatures, however, was not used as the winter temperatures kept the mud temperature low enough to prevent bitumen mobilization downhole.

Logging

The wells were logged by pumping swab cup mounted logging tools down a 114 mm tubing string landed on bottom. Through casing logs (GR and TDT) were run on each well.

Rig Modifications

Hydraulic rigs, although not new in the industry, have experienced mechanical, leakage, and acceptability problems particularily in cold weather. This rig performed well at -35 degrees C. However, numerous developments were required.

Mechanical Developments

Drilling Rig

The drilling rig hydraulic systems were somewhat complicated and required considerable mechanical attention while drilling the first well.

The pushdown mechanism, designed for 22,200 dN, was insufficient to push pipe as well angle and distance increased. The winch motor providing the pushdown capability burnt out when spun backward at high speed during hoisting operations and was replaced with a high speed unit.

The pipe roller used to stabilize and align pipe on pick up and kick out on lay down had to be modified and built to handle collars and large casing.

The Varco iron roughneck experienced many positioning problems, and cable and hydraulic hose failures when forced to work on a 45 degree plane but a booster cylinder, swivel mounted jaws and heavier cables improved the performance.

The mast structure, insufficiently braced for pushdown forces, allowed the inner derrick to spread and the power swivel to fall onto the cylinder but it was repaird by adding strengthening and locking rails.

Equipment Handling

Lifting D.C.s, H.W.D.P. and other tools and equipment for alignment at 45 degrees was difficult.

Casing liner and tubing connections were difficult because of the precise alignment required to start the threads.

Conventional tongs, slips and elevators had to be modified and manhandled into place. This resulted in slow tripping.

Most of these problems were resolved with the installation of a limited reach crane and a pipe handling system.

Downhole Conditions

Directional Drilling

Control of the hole azimuth and angle build-up went extremely well and no severe doglegs were encountered.

Hole Integrity

Sloughing and washout below the conductor barrel created re-entry problems. Cement plugs were required to gain hole stability.

Tight hole conditions probably from tar sand squeezing into the hole required underreaming.

Fishing

Retrieving a parted liner from the hole was not a problem as the high hole angles helped align the fishing tools with the fish.

Summary

The hydraulic rig was designed for vertical and slant hole drilling. To keep investment and standby costs in equipment to a minimum, the rig was to drill vertical wells while the horizontal well concept was being proven.

The horizontal well concept resulted in increased drilling and completion time and costs. The magnitude of the increases was not anticipated.

The information, techniques, equipment design, and expertise gained are invaluable and it is suggested that a significant advance in shallow formation development has been achieved.

The Author

D.C. Loxam is Assistant Superintendent, Operations Department, Oil Sands Group, Texaco Canada Resources Ltd. He has been employed by Texaco for 16 years in various engineering and operating capacities with the last nine being associated with the Athabasca Oil Sands Pilot development. Prior to joining Texaco, Mr. Loxam graduated from the Northern Alberta Insitute of Technology in Edmonton, Alberta, with a diploma in Gas Technology.

FIG. 1

OIL SANDS OF ALBERTA

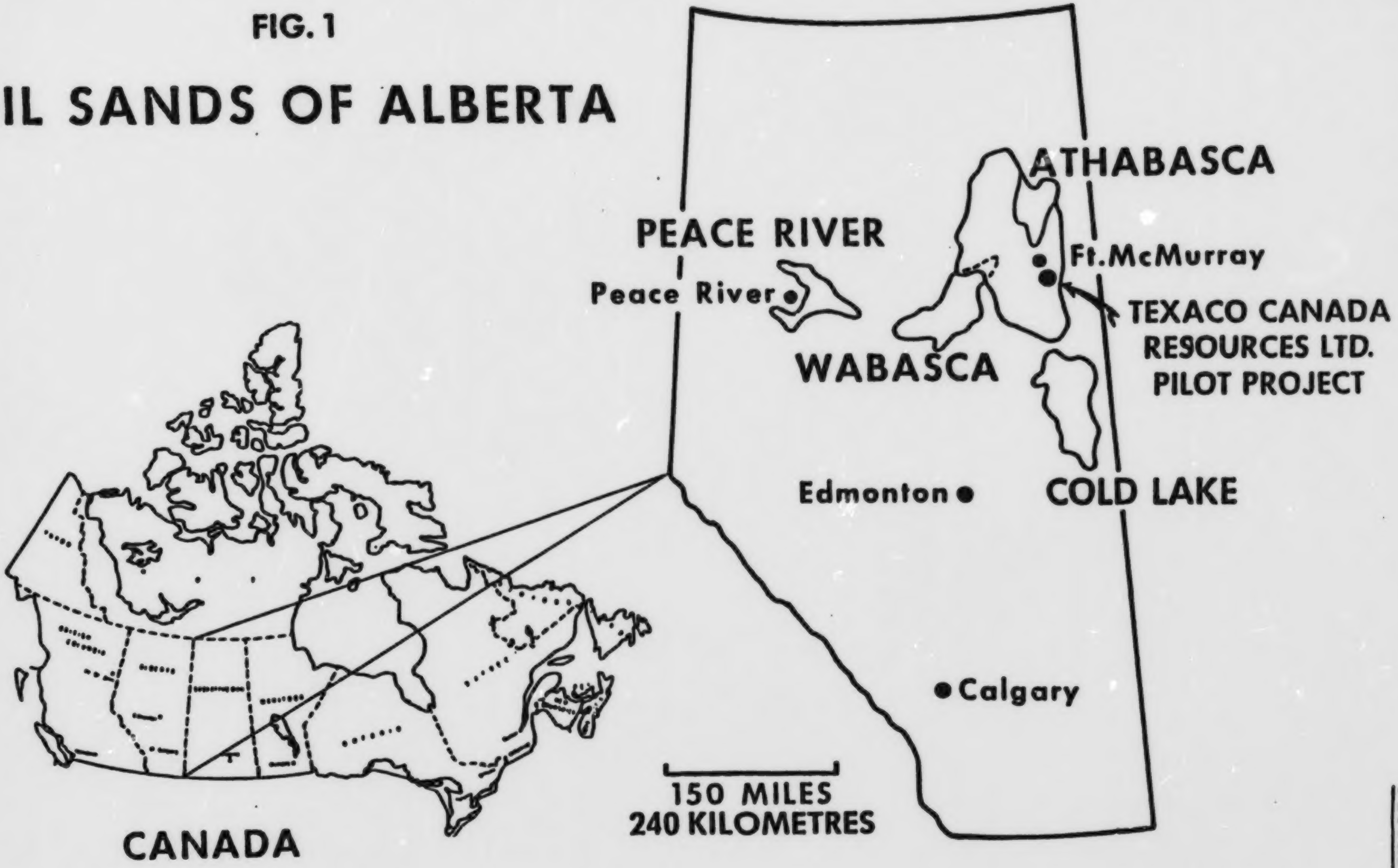
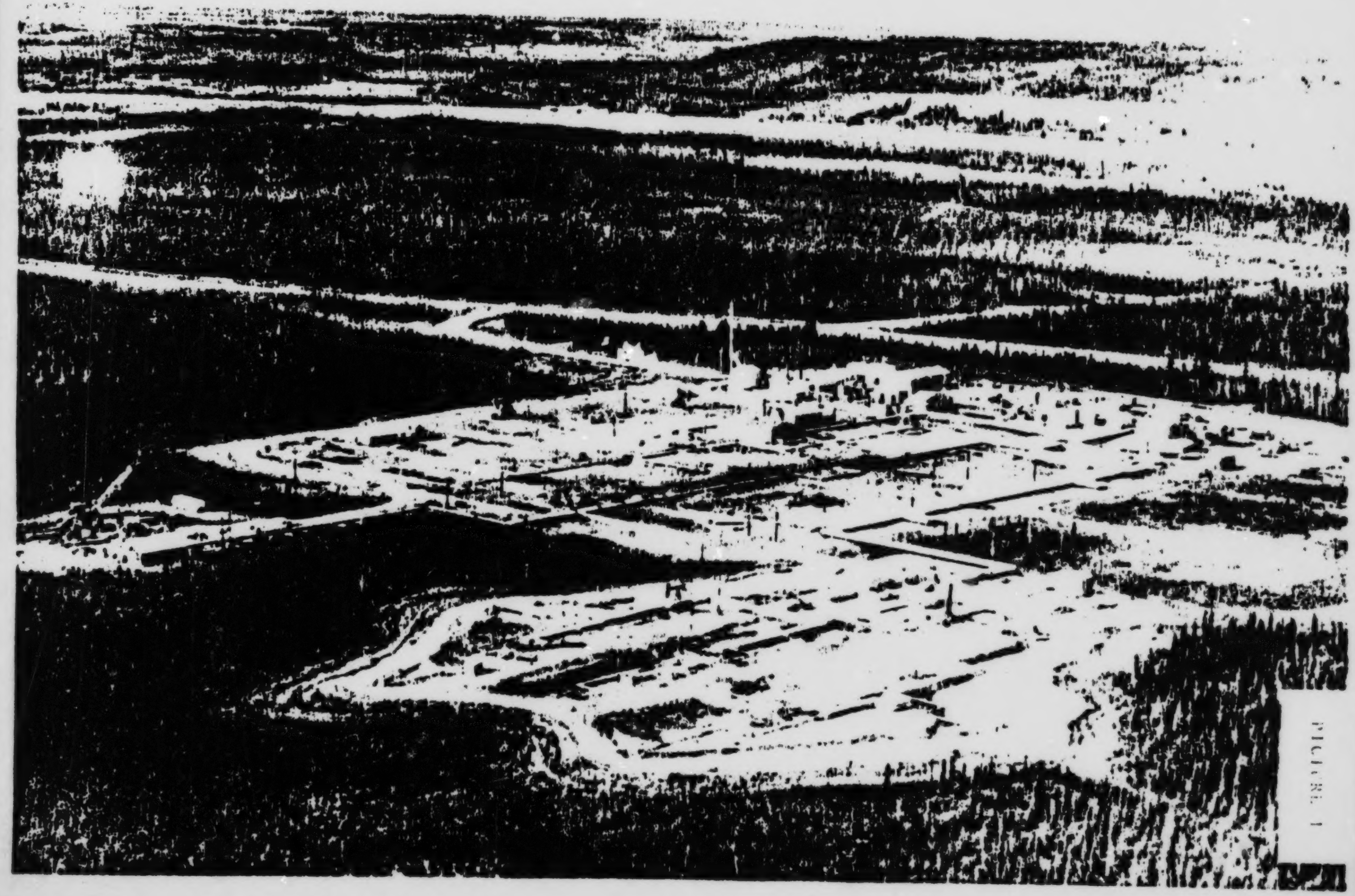

ATHABASCA
PEACE RIVER
Ft.McMurray
Peace River
TEXACO CANADA RESOURCES LTD. PILOT PROJECT
WABASCA
Edmonton
COLD LAKE
Calgary
150 MILES
240 KILOMETRES
CANADA

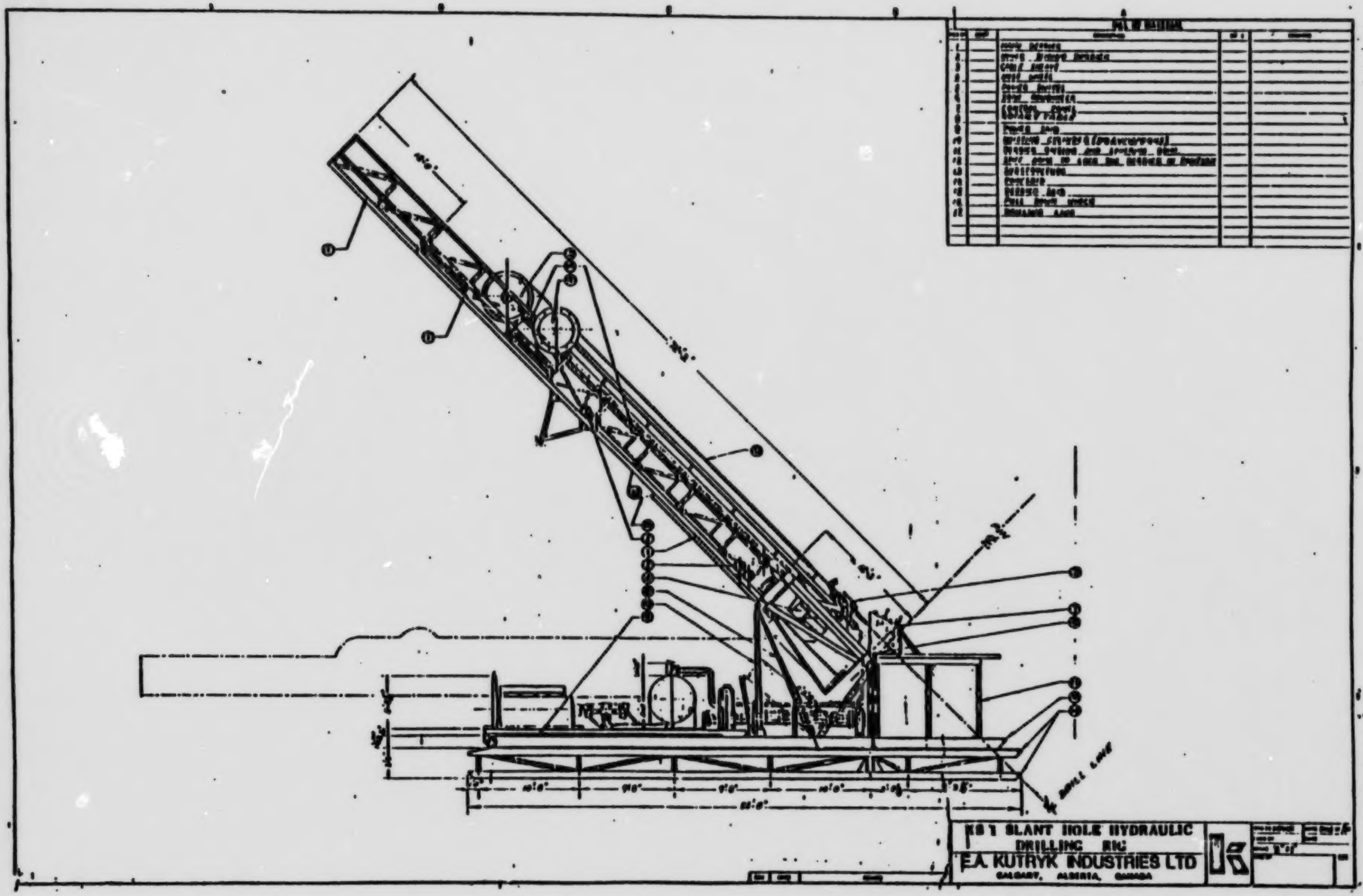
FIGURE 1

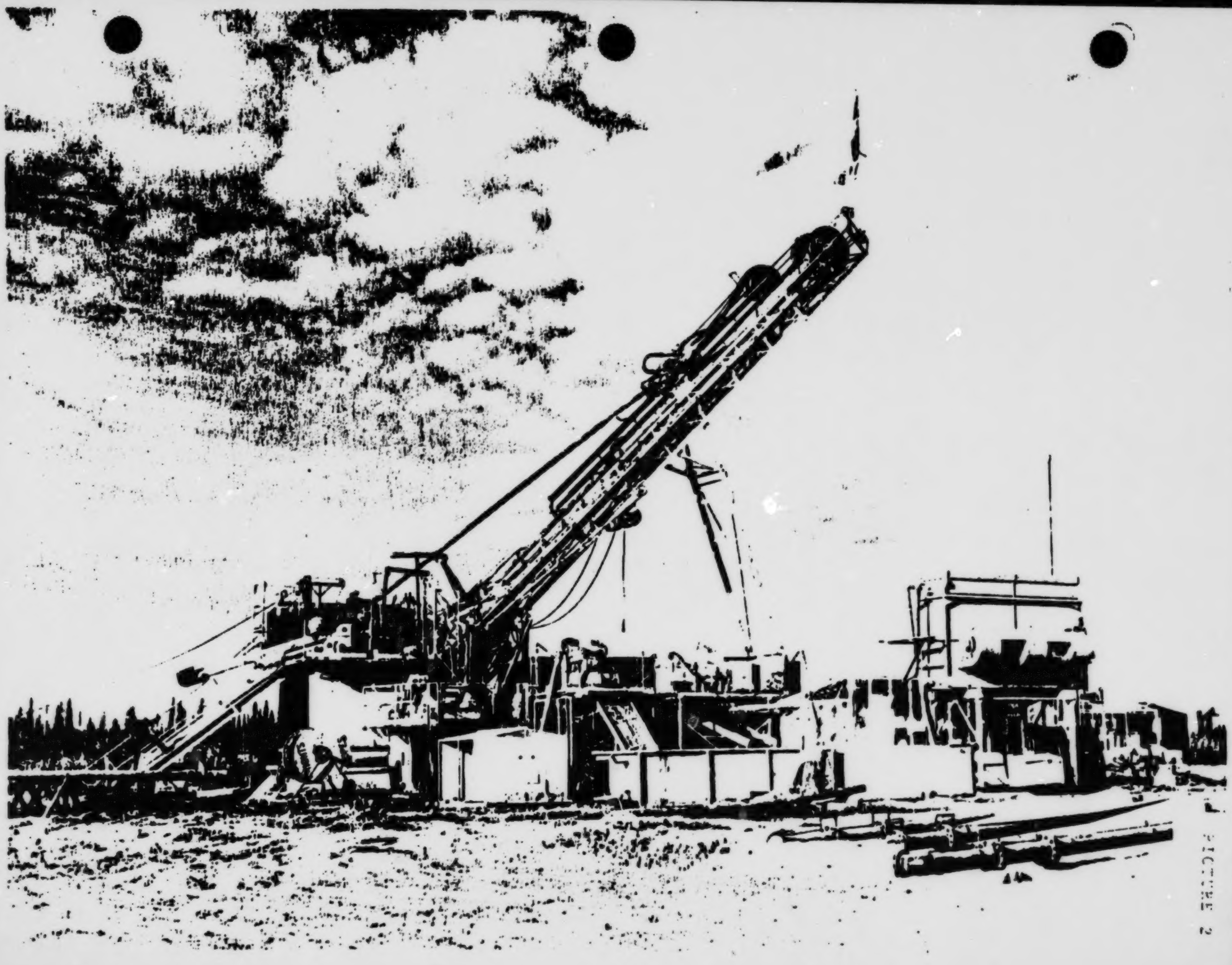


PICTURE 1

FIG. 2

FIGURE 2


KS 1 SLANT HOLE HYDRAULIC DRILLING RIG
E.A. KUTRYK INDUSTRIES LTD
CALGARY, ALBERTA, CANADA
DRILL LINE



PICTURE 2

TABLE 1

KUTRYK KS-1 HYDRAULIC

SLANT-HOLE RIG

KB to Ground
At 0° - 3.95 m
At 45° - 5.55 m

Bottom of Table Beam to Ground
At 0° - 3.65 m
At 45° - 5.10 m

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Hoisting Speed @ Full Load:	35 sec. per single.
Prime Movers:	2 GM 6-71 'N' Series Twin sets.
Mast:	Kutryk 16.75 m single section w/175,000 daN capacity.
Max. Angle:	0° to 45° in 5° increments.
Substructure:	Box type 3.95 m H x 5.50 m L x 3.65 m W.
Power Swivel:	Bowen S3.5 track mounted in derrick w/attachments for casing elevators. Provides 850 daN/m torque @ 150 rpm.
Pump:	National K-500-A w/Hydril K-20-3000 pulsation dampner.
Pump Power:	2 - GM 8V-71 'N' Series w/12V-71 radiators and Allison 855 torque converters.
Mud System:	Unitized skid mounted w/3 compartments complete w/GM powered low pressure system for mixing and/or agitation and fitted w/high pressure roll for mixing and/or agitation. 45 m³ capacity.
Shaker:	2.25 kW Link Belt NRM 145 w/1.21 m x 1.52 m screens.
Water Tank:	45 m³ capacity, mounted on skid w/toolhouse. Features drop in doghouse.
Toolhouse:	On skid w/water tank/doghouse unit. 4 m L x 3.04 m W and includes oil storage.
Power Plant:	2 - Cat 315 engines w/30 kW generators. Housed in combination building with accumulator and change house.

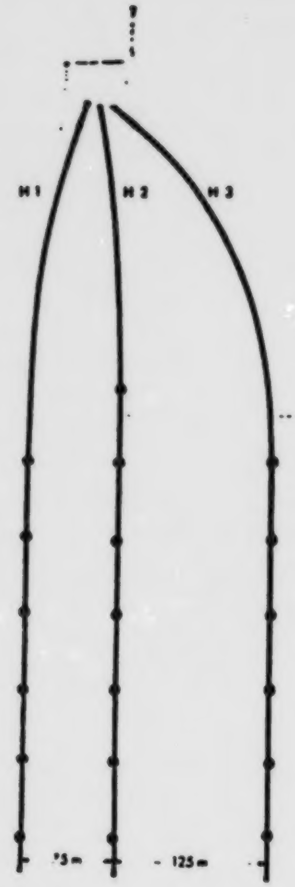

H 1
H 2
H 3
75 m
125 m

FIG. 3

HORIZONTAL HOLES H1 H2 AND H3 D DRILLING PROGRAM

PLAN

50 m

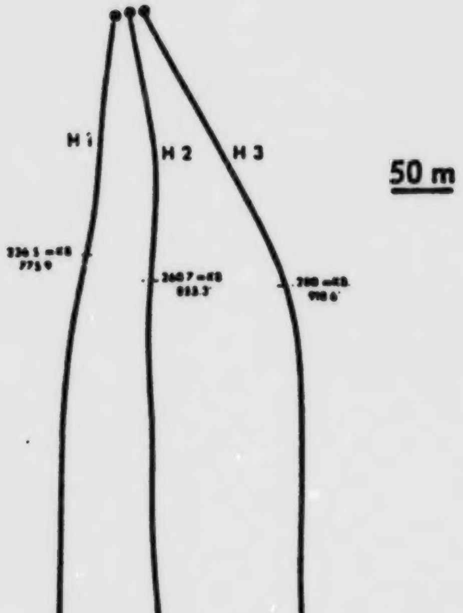

H 1
H 2
H 3
50 m
236.5 mKB
775.9'
260.7 mKB
855.3'
280 mKB
918.6'
559.8 mKB
1836.6'
591.7 mKB
1941.3'
629 mKB
2063.6'
80m
262.5
120m
393.7'

FIG. 4

ATHABASCA PILOT PROJECT HORIZONTAL HOLES AS DRILLED

CONFINED 6.2 ha (15.4 ACRES)

PICTURE 3

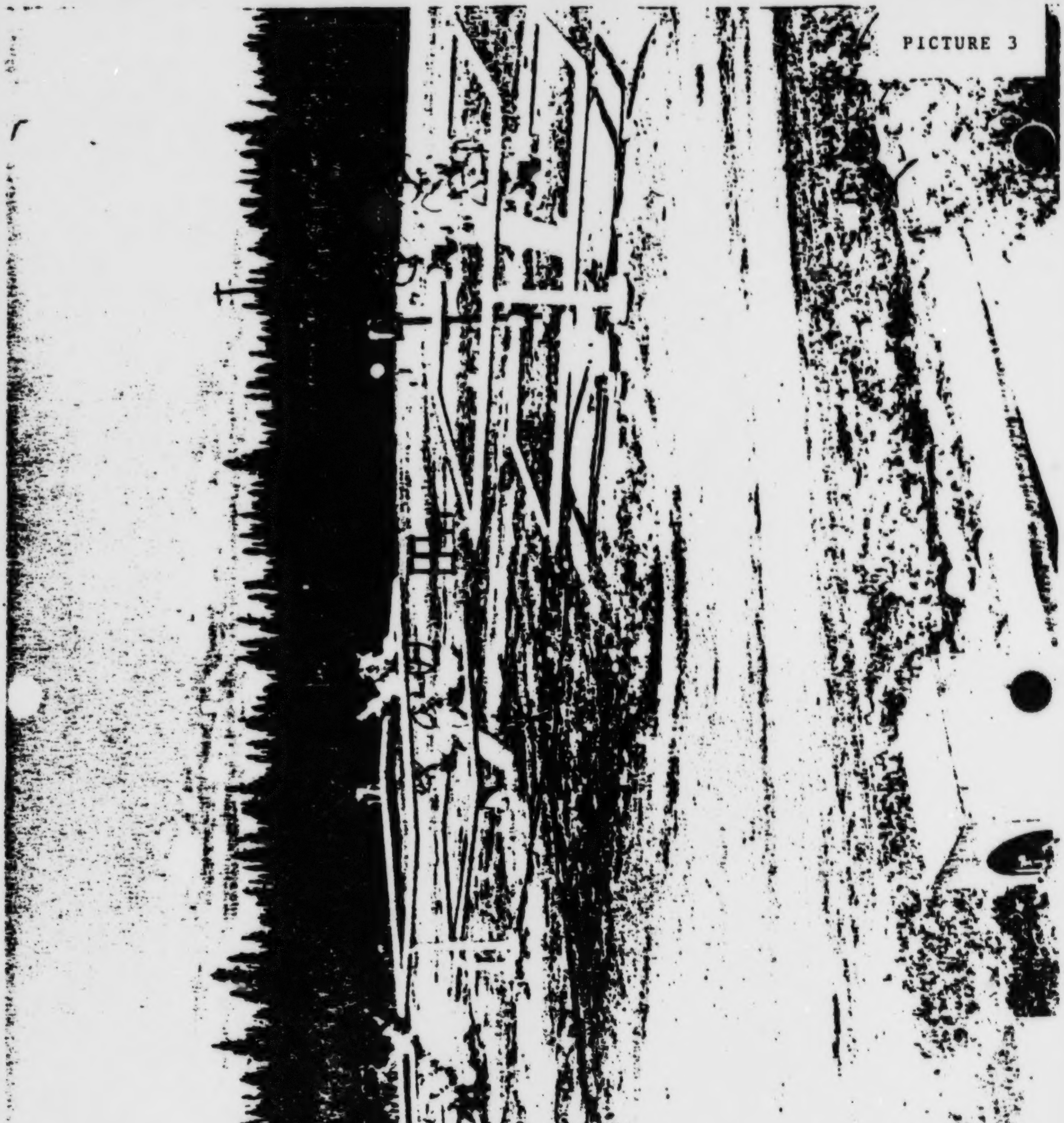
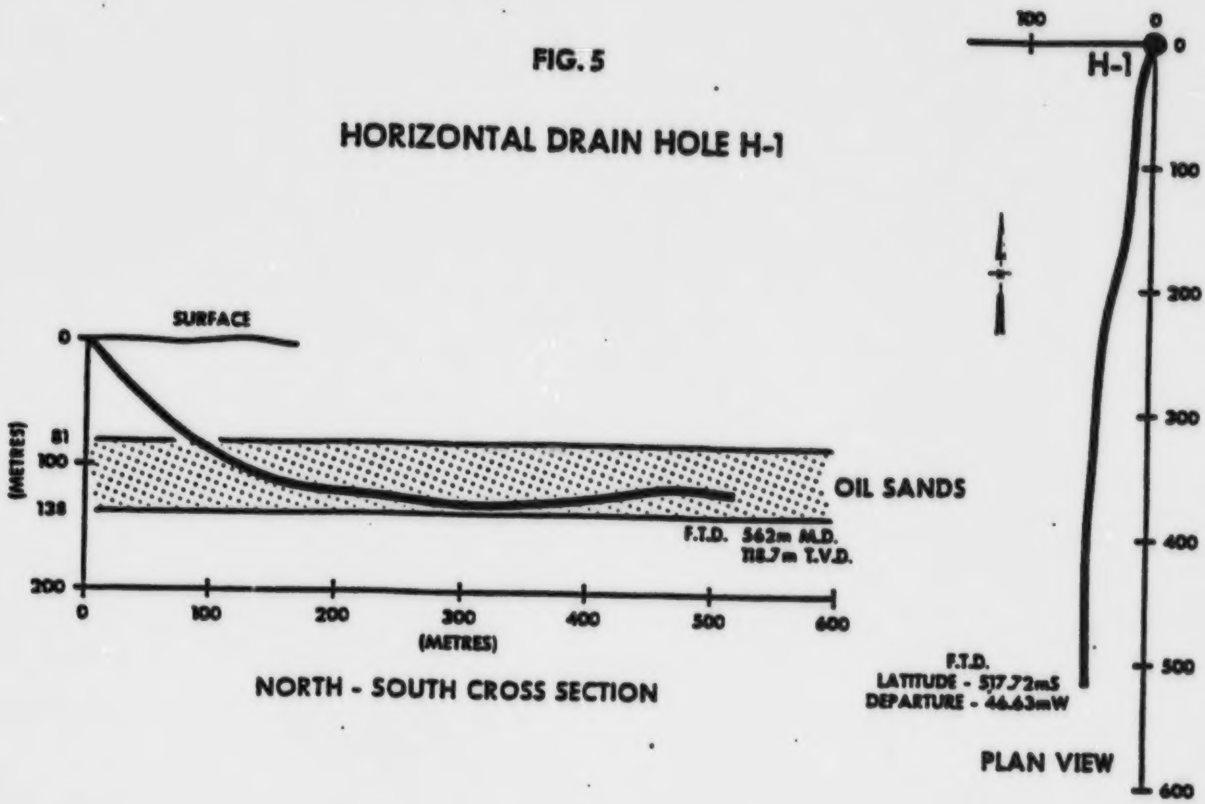


FIG. 5

HORIZONTAL DRAIN HOLE H-1


SURFACE
0
81
100
138
200
(METRES)
OIL SANDS
F.T.D. 562m M.D.
118.7m T.V.D.
0
100
200
300
400
500
600
(METRES)
100
0
H-1
0
100
200
300
400
500
600
F.T.D.
LATITUDE - 517.72mS
DEPARTURE - 46.63mW

NORTH - SOUTH CROSS SECTION

PLAN VIEW

FIG. 6

H-1 DEPTH VS DAYS

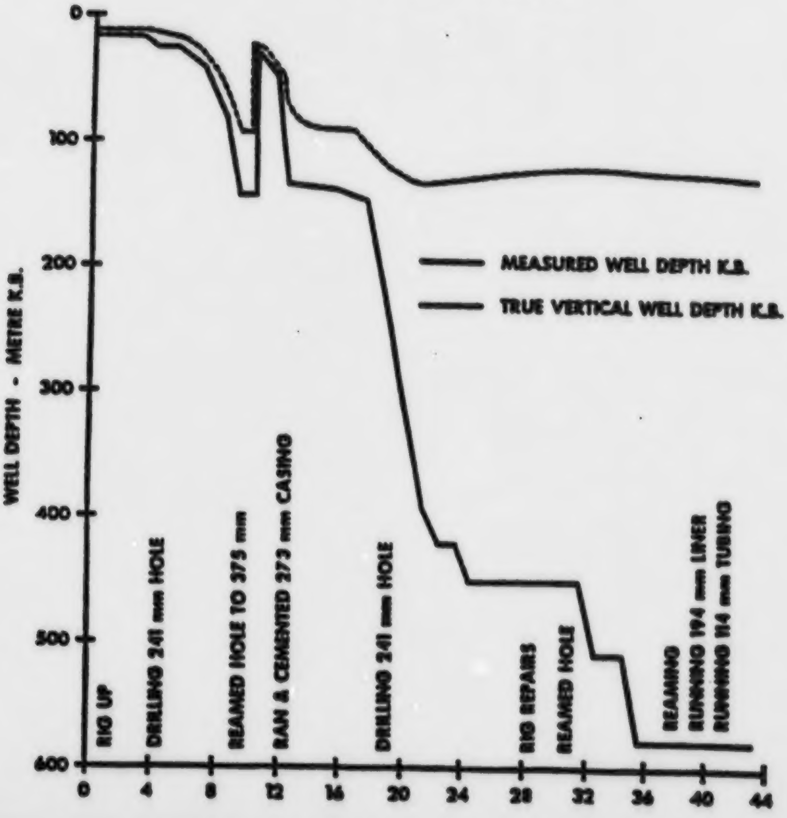
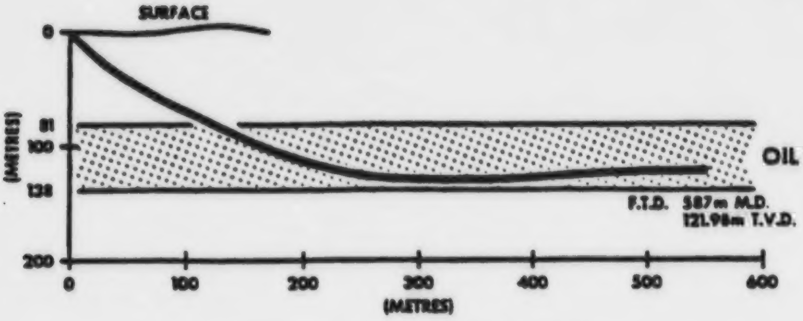
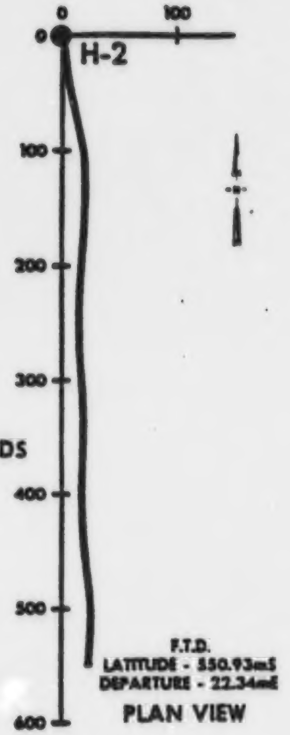


FIG. 7

HORIZONTAL DRAIN HOLE H-2


SURFACE
0
81
100
138
200
(METRES)
OIL SANDS
F.T.D. 587m M.D.
121.98m T.V.D.
0
100
200
300
400
500
600
(METRES)

NORTH - SOUTH CROSS SECTION


0
100
0
H-2
100
200
300
400
500
600
F.T.D.
LATITUDE - 550.93mS
DEPARTURE - 22.34mE

PLAN VIEW

FIG. 8

H-2 DEPTH VS DAYS

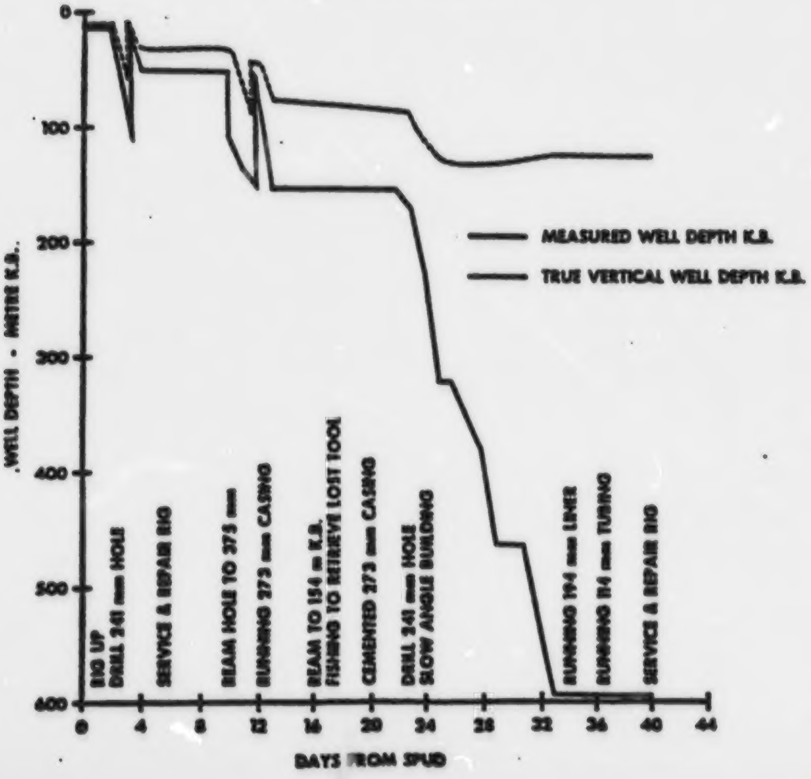
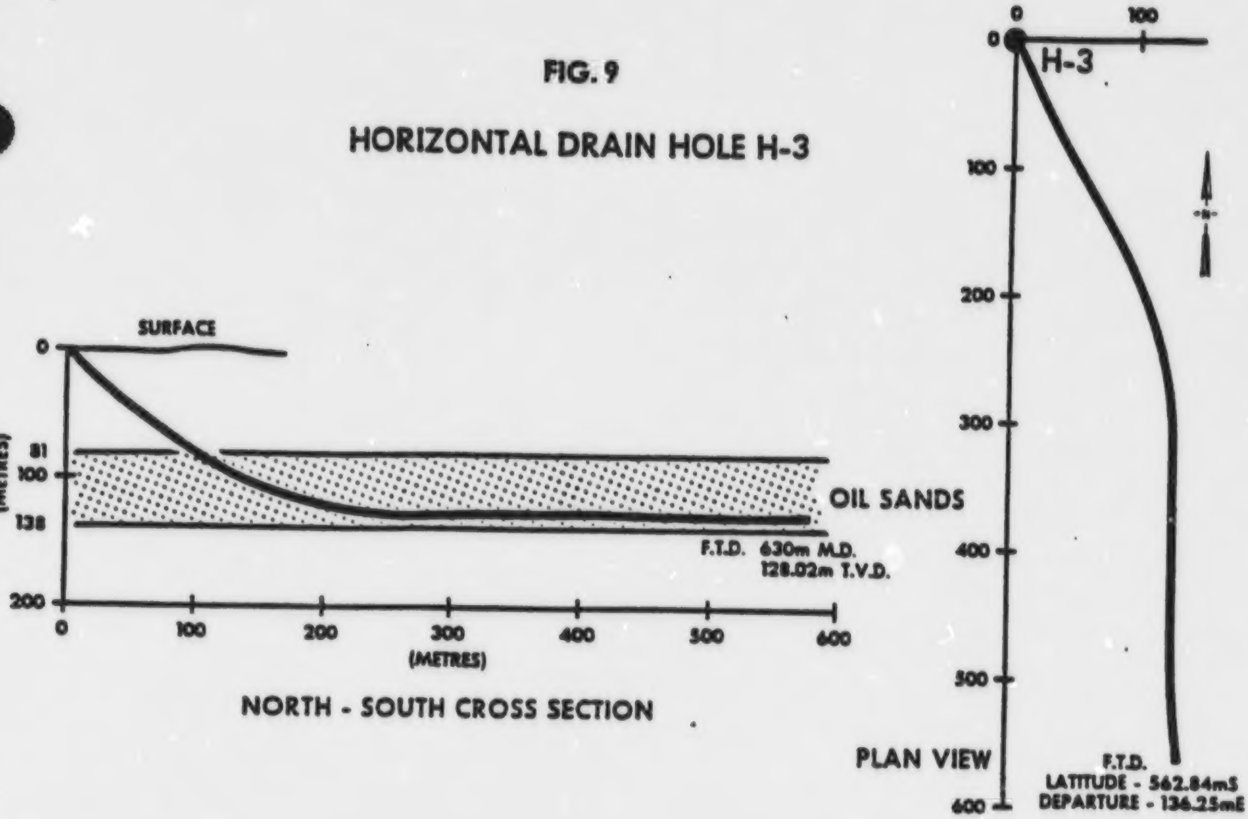


FIG. 9

HORIZONTAL DRAIN HOLE H-3


SURFACE
0
81
100
138
200
(METRES)
OIL SANDS
F.T.D. 630m M.D.
128.02m T.V.D.
0
100
200
300
400
500
600
(METRES)
0
100
H-3
0
100
200
300
400
500
600
N
F.T.D.
LATITUDE - 562.84mS
DEPARTURE - 136.25mE

NORTH - SOUTH CROSS SECTION

PLAN VIEW

FIG. 10

H-3 DEPTH VS DAYS

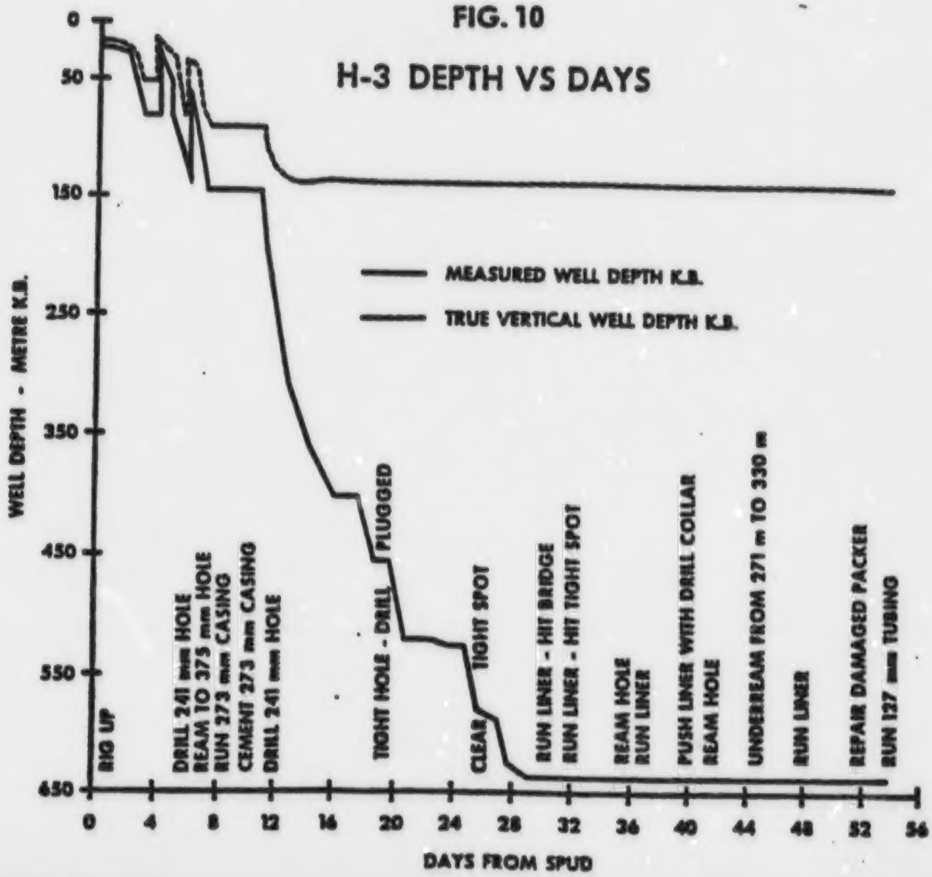
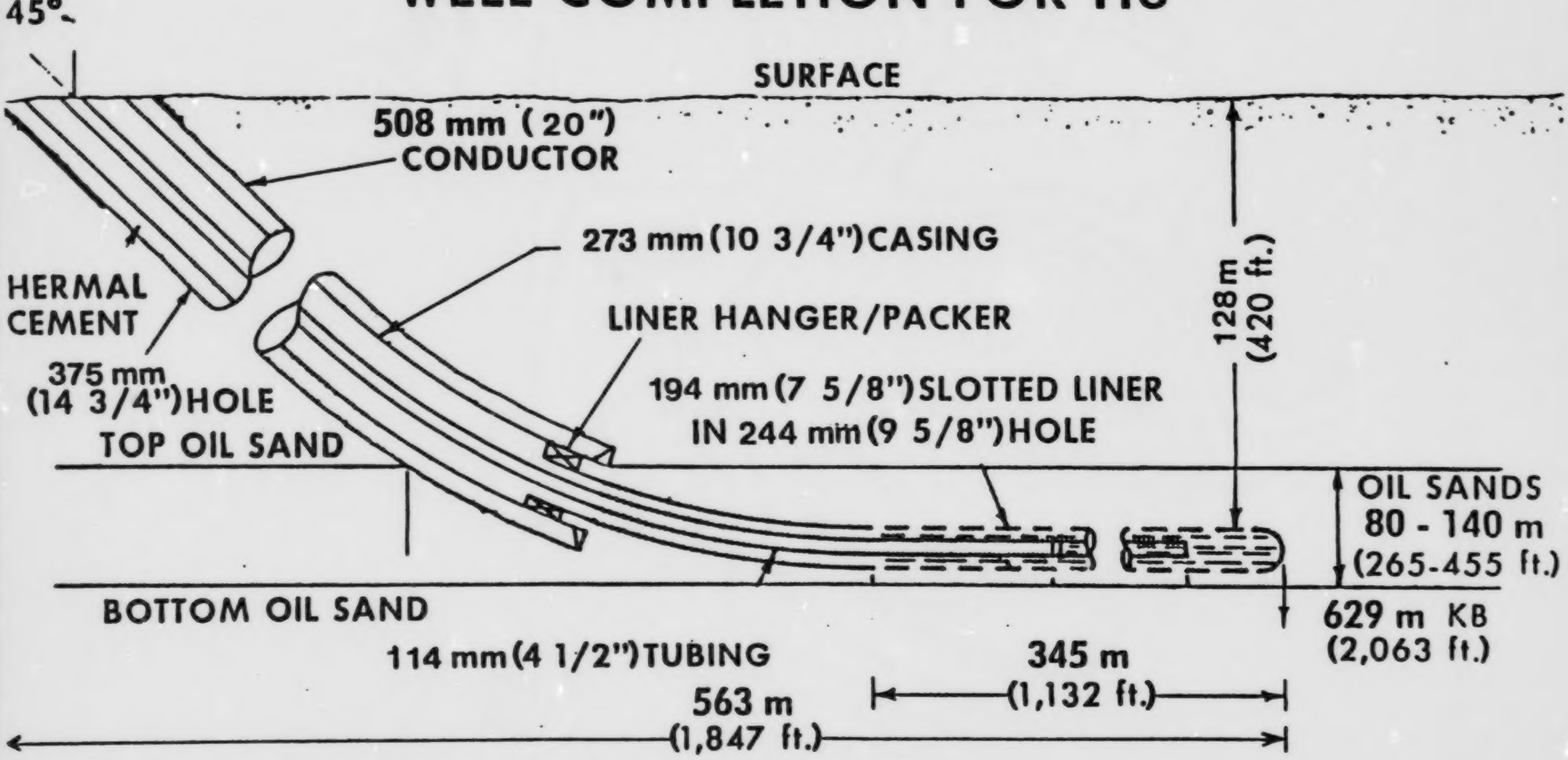
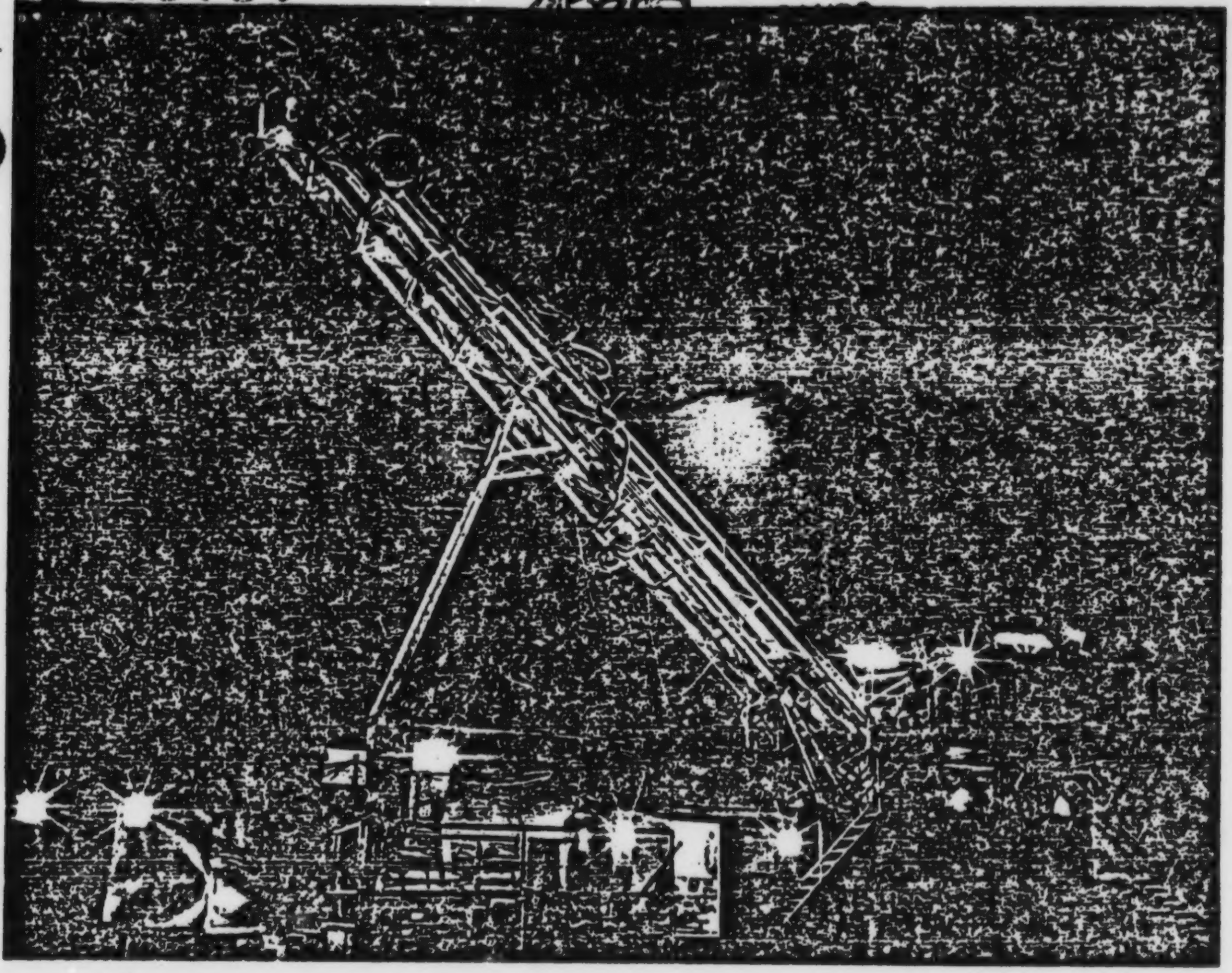


FIG. 11

ATHABASCA PILOT PROJECT
PATTERN III
WELL COMPLETION FOR H3


45°
SURFACE
508 mm (20")
CONDUCTOR
273 mm (10 3/4") CASING
HERMAL
CEMENT
LINER HANGER/PACKER
375 mm
(14 3/4") HOLE
194 mm (7 5/8") SLOTTED LINER
IN 244 mm (9 5/8") HOLE
128 m
(420 ft.)
TOP OIL SAND
OIL SANDS
80 - 140 m
(265-455 ft.)
BOTTOM OIL SAND
629 m KB
(2,063 ft.)
114 mm (4 1/2") TUBING
345 m
(1,132 ft.)
563 m
(1,847 ft.)

008737



Texaco Canada Completes Unique Horizontal Drilling Program

(19)

by D. C. Loxam, *Project Assistant, Oil Sands Group,*
Texaco Canada Resources Ltd., Calgary, Alberta

Alberta OIL SANDS
INFORMATION CENTRE

Texaco Canada Resources Ltd. recently completed an innovative drilling program to tap shallow reserves in its Athabasca oil sands lease, south and east of Fort McMurray, Alberta, Canada (Fig. 1). Texaco successfully drilled three wells using a drilling rig with a 45°-slanted mast.

Since 1972, Texaco has operated an in-situ pilot project in their Athabasca field. In 1979, the company recognized the need to reduce capital cost for a commercial venture while providing improved recovery in development of the oil sands.

Texaco could only develop these shallow 260- to 660-ft (80- to 200-m) oil sands by drilling highly deviated wells. Furthermore, the combination of shallow depth and unconsolidated bituminous sands presented unique drilling problems to obtain long horizontal sections. Although the path followed in drilling was not always as proposed, the company achieved its objectives.

V54, N11

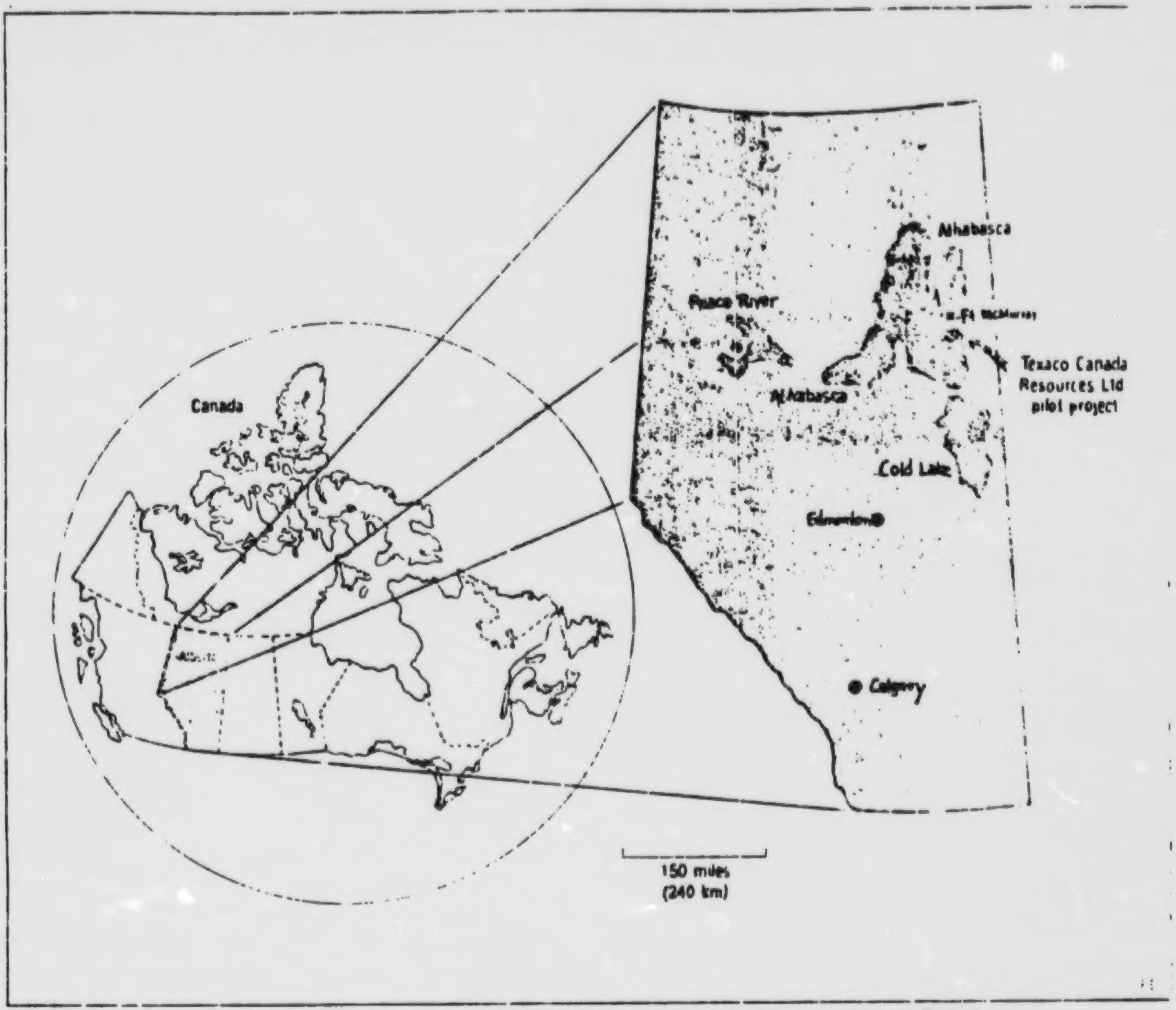


Fig. 1. Texaco's Athabasca oil sand pilot project is located southeast of Fort McMurray, Alberta, Canada

The Rig

To handle the unusual drilling problems, Texaco contracted Westburne Drilling (Canada) Ltd. of Calgary to build a new rig to drill slant wells to 45° from the vertical. A hydraulic slant drilling rig was designed and built to Westburne specifications, by E.A. Kutryk Industries Ltd. of Calgary (Table 1).

Although the wells were shallow, pipe drag during lifting and lowering operations was significant. A lifting capacity of 224,800 lb (100,000 decaNewtons, dN) was required to pull off bottom with the drill string or liner. Conversely, a pushdown capacity of 50,000 lb (22,200dN) was required to obtain force on the drill bit or to push the liner to bottom. The push-down capability was required to apply the required forces to the pipe being run into the well as only 70% of the weight of the drill collars and heavyweight drill pipe is applied down the drill string at 45°. This effective weight rapidly declines, as the well bore angle increases.

The rig hydraulically raises, lowers, and rotates the tubulars. An upper movable mast section is fixed to a large hydraulic cylinder and is supported in a base or stationary lower mast section. This provides pipe raising and lowering capability through a cable system, tied to a power swivel cart, strung up and over large sheeves on top of the movable mast, and anchored to the base of the stationary mast. This arrangement provides a two-to-one travel ratio for the cable versus cylinder movement.

A Bowen model 3.5 power swivel mounted on the cart, traveling in a track assembly on the movable mast, provides rotary power and direct connection to the tubulars. Thus conventional blocks, bails, and elevators are not used, which eliminates pipe alignment problems.

A Varco iron roughneck is employed to handle drill pipe, drill collar, and heavy tool connections. The remainder of the rig, including mud mixing and circulating systems, followed conventional practices.

Drilling Operations

Texaco was successful in drilling all three horizontal wells from a single drill pad at the McMurray pilot project. These wells have an average 1,095 ft (334 m) horizontal section at an average true vertical depth (TVD) of 413 ft (126m). The average total drilled depth (DD) is 1,957 ft (597m) with the horizontal sections

Aerial view of Westburne Drilling (Canada) Ltd. Rig 30 drilling a horizontal hole for Texaco Canada Resources Ltd. at its Fort McMurray pilot project.

spaced at 246 ft (75 m) and 410 ft (124 m), respectively. Figs. 2 and 3 show the planned and actual drilling programs for all three wells. Drilling time averaged 46 days per well (Figs. 4 through 9).

The three wells have 49 ft (15 m) of predriven 20-in. conductor pipe set at 45° to the vertical and orientated to give the required azimuth angle for the completions.

Each well was directionally drilled with a 9½-in. pilot hole building angle at 5°/98 ft with 6¼-in. Dynadrill or Navidrill mud motors from the conductor pipe into the top of the bituminous sands at 416 ft (127 m) DD. TVD was 262 ft (80 m) and an inclination of 54° from vertical.

The pilot hole was reamed to 14¾-in. and a string of 10¾-in., 55.5 lb/ft BTC MN80 seamless casing was run. The casing was set at 426 ft (130 m) DD and cemented with thermal type cement.

Drilling continued with 9½-in. bits, again powered by Navidrill or Dynadrill mud motors building angle at 5°/98 ft to 984 ft (300 m) DD average (393 ft, or 120 m TVD) where an angle of 90° was achieved. The drilling assembly then was altered to counteract the drop-off effect of gravity on the drill string and to maintain the horizontal hole to well total depth.

A 7⅝-in., 33.7 lb/ft BTC MN80 seamless liner was run and set with the horizontal section slotted with 120 in. of 30/1,000 in. slots per foot. The upper section from casing to slotted liner was blank pipe. The liner was not cemented.

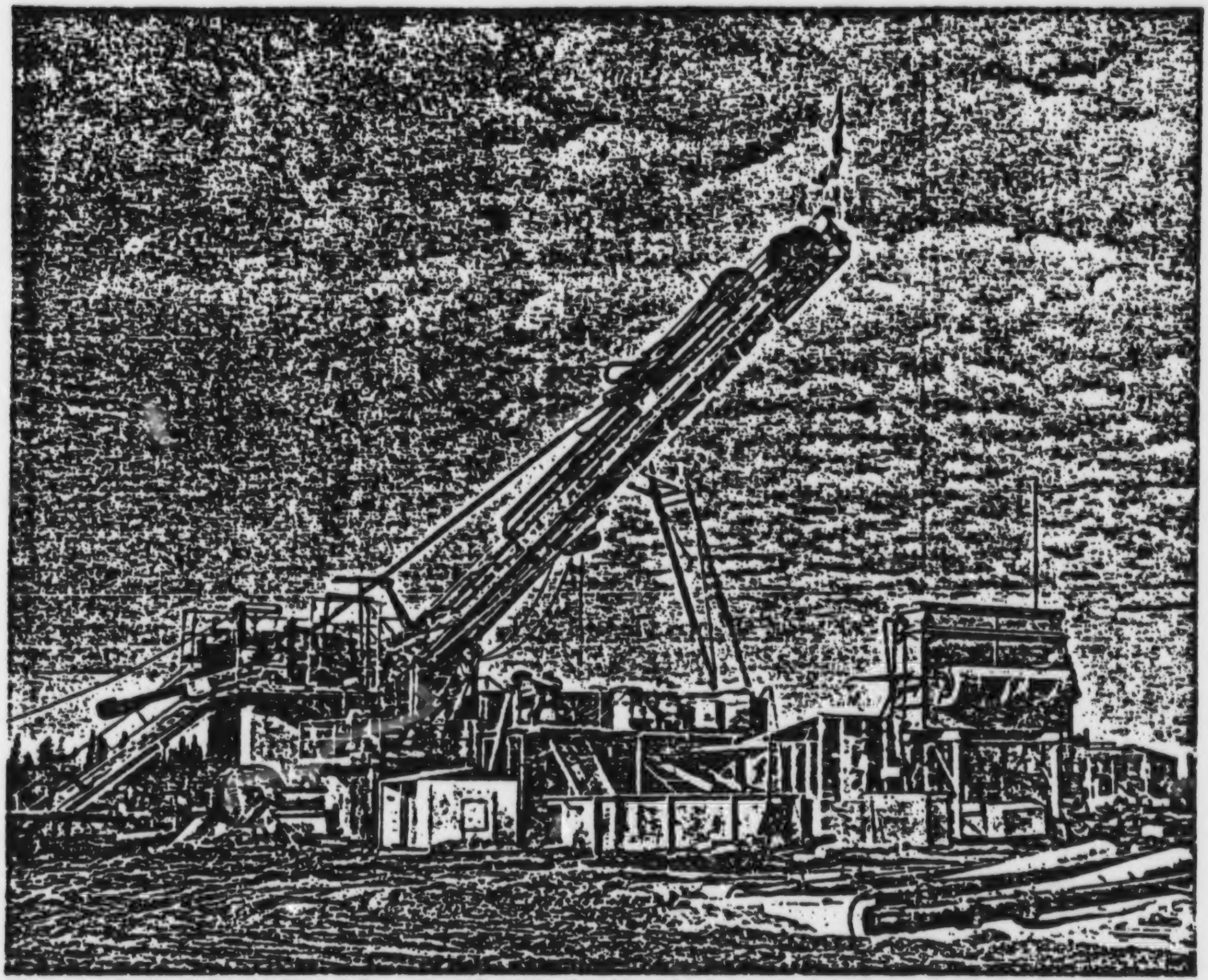
A string of 4½-in., 15.1-lb 500 95 LT&C tubing was run to bottom for logging and then changed to a completion string. A thermocouple string, preinstalled in 1 in. endless tubing, was strapped to the 4¼-in. tubing and landed with the tubing approximately halfway down the slotted liner section. The well was circulated to clean water (Fig. 10).

Drill String Assemblies

Downhole mud motors, Dynadrills, or Navidrills were used to continuously build angle from the bottom of the conductor pipe to the horizontal position at a rate of 5°/98 ft. Long-tooth soft formation bits were used on the drills with good penetration and bit life.

Various bent sub assemblies with both types of mud motors were used to achieve the required angle build-up. Bent housing drills also were used with and without bent subs at various intervals to stay on track. Stabilizers were used to maintain hole trajectory.

Three Monel drill collars were run behind the drills to reduce magnetic interference on the survey tools. Heavyweight drill pipe with drill collars was used above the drill assemblies to add weight and provide a



Westburne Drilling's Rig 30. Mud chiller with condenser enclosed in a plastic covering is in the lower right-hand corner, with the cooler unit in front of the elevator stand. In the lower middle, a sludge tank catches the discharge from the mud cleaner and the centrifuge is located on the elevated platform behind the tank. The slant derrick with the stationary derrick is painted white, the movable derrick is painted red, and the main cylinder is painted blue. At the left of the photo is the working floor with hydraulic crane and controls mounted on the substructure over the slant wellhead.

stiff assembly for surface push down in the system. In the horizontal section of the third well, lightweight drill pipe was used instead of heavyweight drill pipe. The heavyweight drill pipe was maintained in the upper section of the hole to obtain maximum benefit from the weight as the rig's push-down capability proved insufficient to obtain the desired drill rate and penetration.

Conventional rotary drilling was carried out in the wells to ream for the production casing. A nonrotating stabilizer preceded the hole opener to prevent drift or a tendency to bury itself. Rotary drilling also was used very successfully for underreaming a portion of the third well where tight hole prohibited running the liner.

Directional Surveying and Control

The target of 984 ft (300 m) for the horizontal portion of the wells was achieved in all cases and the deviation control improved with each well.

Knowledge of the accurate location of hole and direction of progress at any time was vital to the completion of these wells. A steering tool located in the nonmagnetic drill collar string and connected to surface by wireline was used at all times while drilling. This tool provided constant surface digital data on hole inclination and azimuth while drilling. To confirm steering tool directional information, multishot surveys were run and reasonable correlation was obtained.

Mud System

A simple aquagel-bentonite system was used to drill to the top of the tar sands. A polymer mud system was used to drill through the sands to prevent clay swelling and tar sticking in the well. A desander and a centrifuge cleaning system were used at all times to keep solids to a minimum in the system, thus reducing mud motor wear and mud weight buildup.

A chiller unit was installed in the mud system to maintain low circulating temperatures. However, the unit was not used, as the ambient temperature kept the

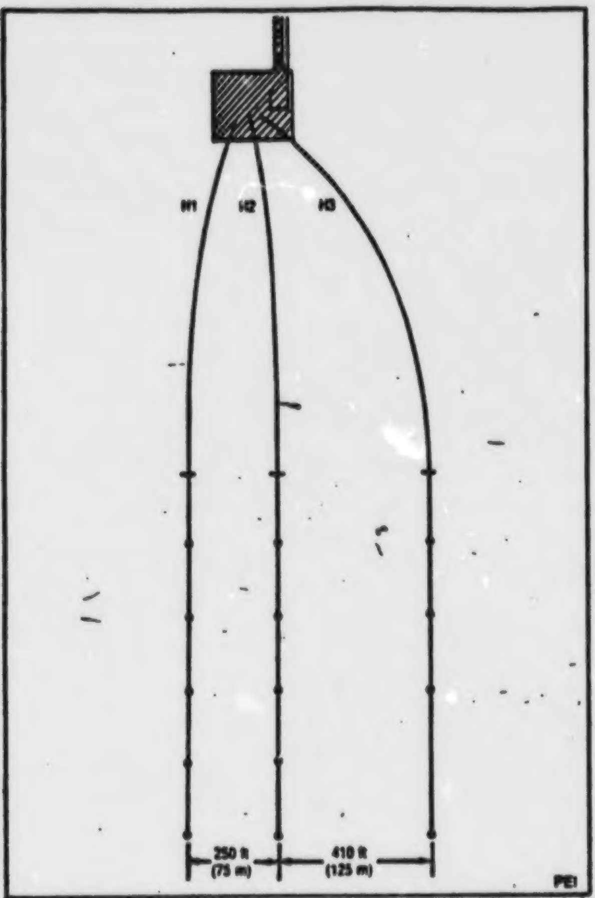


Fig. 2. Planned drilling program for horizontal holes H1, H2, and H3.

system temperature low enough and under control in the winter drilling season to prevent the bitumen in the sands from becoming mobile and creating sticking problems on the pipe.

Logging

The three wells were logged by running a 4½-in. tubing string to bottom and pumping the logging tools with swab cups attached down the hole. Through-casing logs (GR and TDT) were run on each well.

Rig Modifications

Hydraulic rigs are not new in the drilling industry, but have in the past experienced mechanical, leakage, and acceptability problems, particularly in cold weather. This rig has performed reasonably well at -35 C, a temperature not uncommon to the winter drilling seasons in northern Alberta.

However, numerous developments were required with the new equipment, the modification of conventional equipment, drilling techniques, and downhole conditions.

Mechanical Developments

Drilling rig. The hydraulic systems have proved to be unnecessarily complicated. They required considerable mechanical attention for setting, minor leaks, and repairs during the drilling of the first well. Thereafter, minimal problems occurred.

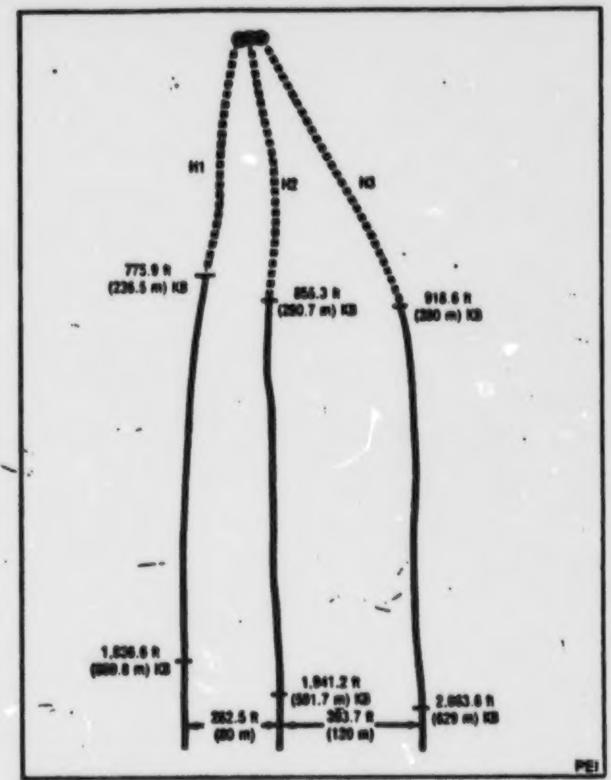


Fig. 3. Actual drilling program for horizontal holes H1, H2, and H3, confined to 15.4 acres.

The push-down mechanism was designed to provide a maximum of 50,000 lb (22,200 dN) which was insufficient to push pipe as well angle inclination and distance increased. The winch motor, which provides the push-down capability, was not provided with a clutch. This caused winch motor burnout when spun backward at high speed during hoisting operations but was solved by installing a high-speed motor.

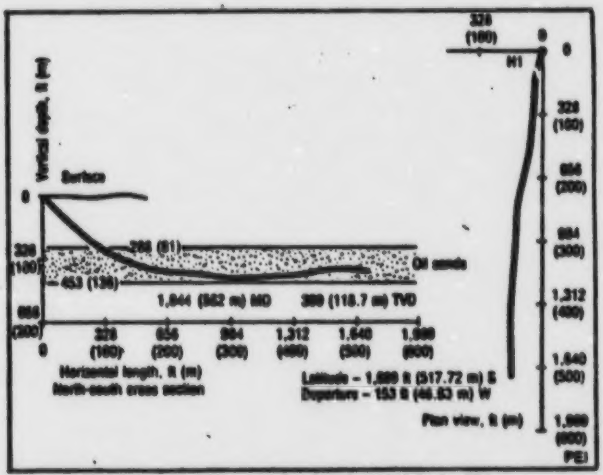


Fig. 4. Well bore program for horizontal hole H1.

The pipe roller, used to stabilize and align pipe on

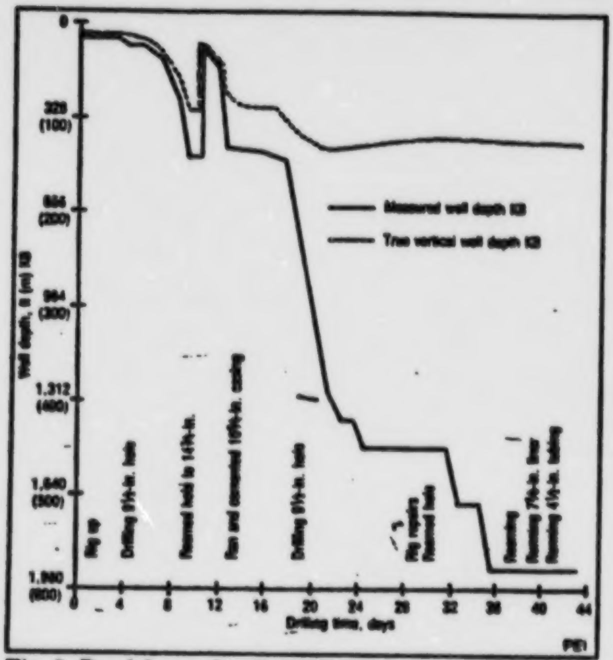


Fig. 5. Breakdown of well depth versus days for horizontal hole H1.

pickup and kick out the bottom of the pipe toward the racks during laydown, proved to be not strong enough. It had to be modified and built to handle collars and large casing.

The Varco iron roughneck, which is designed to work on a horizontal plane, experienced many positioning, cable, and hydraulic hose failures when forced to work on a 45° plane. A booster hydraulic cylinder, swivel-mounted jaws, and heavier cables improved the performance.

The mast structure was insufficiently braced to withstand push-down forces which caused the inner derrick to spread and allowed the power swivel to fall into the derrick. Strengthening and locking rails prevented further problems.

Equipment handling. Drill collars, heavyweight drill pipe, and other heavy tools and equipment were difficult to lift onto the rig floor. Correct alignment at 45° for connections also was difficult with this heavy equipment. Installing a limited-reach hydraulic crane alleviated most of these problems.

Casing, liner, and tubing connections were very difficult because of the precise angle of alignment required by casing threads on this pipe.

Conventional equipment such as tongs, slips, elevators, etc., had to be modified or manhandled into place. Considerable experimenting was necessary to determine the most feasible method of manipulation.

These problems resulted in slow pipe handling and tripping. Many of these problems were solved by the hydraulic crane and the addition of a pipe laydown system used on a subsequent workover.

Downhole Conditions

Directional drilling. Control of the hole azimuth and angle buildup went extremely well and no severe doglegs were encountered to make running pipe difficult.

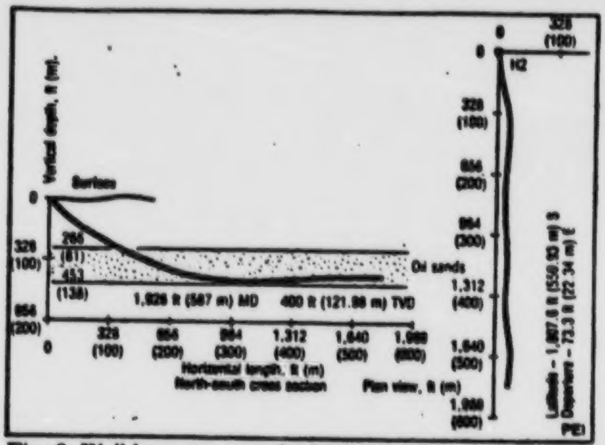


Fig. 6. Well bore program for horizontal hole H2.

Hole integrity. Sloughing and washout conditions on two wells just below the conductor barrel created reentry problems. Several cement plugs were necessary to gain hole stability before reentry could be achieved.

Formation swelling created tight spots in the tar sands of the third well. This condition could have been swelling clays or tar sand squeezing into the hole. Reaming did not seem to alleviate the situation and an underreaming technique for horizontal holes was developed to eliminate the problem.

Fishing. No difficulty was encountered in the hole when retrieval of a parted liner became necessary. The

TABLE 1. Kutryk KS-1 hydraulic slant-hole rig specifications

Kelly bushing to ground	Bottom of table beam to ground
at 0° – 13 ft (3.[illegible] m)	at 0° – 12 ft (3.65 m)
at 45° – 18.2 (5.55 m)	at 45° – 16.7 ft (5.18 m)

Hydraulic system – 34,000 kPa skid-mounted
Maximum lifting capacity – 110,000 dN with 450 kW to ram
Maximum hoisting travel – 45 ft (13.70 m)
Maximum hoisting speed – 10 sec/single
Hoisting speed at full load – 35 sec/single
Prime movers – Two GM 6-71 N Series Twin sets
Mast – Kutryk 55-ft (16.75-m) single section with 175,000 dN capacity
Maximum angle – 0° to 45° in 5° increments
Substructure – Box type; 13 ft (3.95 m) H by 18 ft (5.50 m) L by 12 ft (3.65 m) W
Power swivel – Bowen S3.5 track-mounted in derrick with attachments for casing elevators; provides 850 dN/m torque at 150 rpm
Pump – National K-500-A with Hydril K-20-3000 pulsation dampener
Pump power – Two GM 8V-71 N Series with 12V-71 radiators and Allison 855 torque converters
Mud system – Unitized skid-mounted with three compartments complete with GM-powered low-pressure system for mixing and agitation and fitted with high-pressure roll for mixing and agitation – 45 cu ft capacity
Shaker – 2.25 kW Link Belt NRM 145 with 4 ft (1.21 m) by 5 ft (1.52 m) screens
Water tank – 45 cu ft capacity, mounted on skid with toolhouse; features drop in doghouse
Toolhouse – On skid with water tank-doghouse unit; 13.1 ft (4 m) L by 10 ft (3.04 m) W and includes oil storage
Power plant – Two Cat 315 engines with 30-kW generators; housed in combination building with accumulator and change house

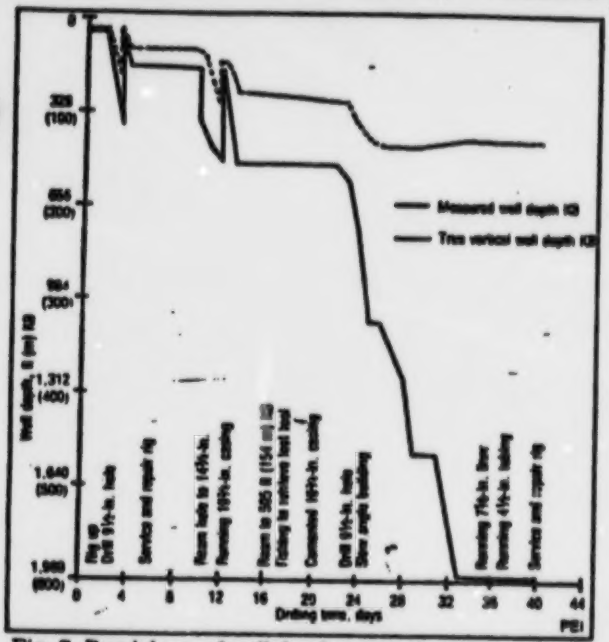


Fig. 7. Breakdown of well depth versus days for horizontal hole H2.

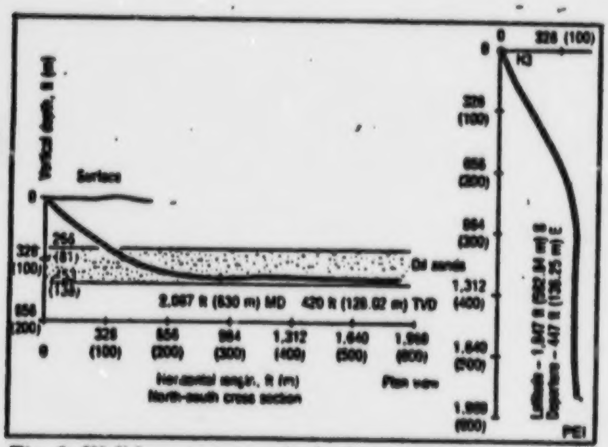

Vertical depth, ft (m)
Surface
Oil sands
2,087 ft (630 m) MD
420 ft (128.02 m) TVD
Horizontal length, ft (m)
North-south cross section
Plan view
H3
PEI

Fig. 8. Well bore program for horizontal hole H3.

high hole angles helped to obtain alignment of the fishing tools and the fish.

The hydraulic rig was designed for both vertical and slant-hole drilling. This concept would keep investment and standby costs in equipment to a minimum while the horizontal well system was being proven. The design concept, however, had varying degrees of influence on the successful completion of the three wells. It increased their drilling and completion time and costs. Many of the mechanical problems were developmental in nature and the downhole problems greater in magnitude than foreseen.

The information, techniques, equipment design, and expertise gained from drilling the three horizontal wells are invaluable in the quest toward commercial production of bitumen by in-situ methods. By drilling to 2,082 ft DD (635 m) with 1,246 ft (390 m) of hole horizontal in the oil sands, it is suggested that a significant advance in very shallow formation drilling has been achieved. Drilling of similar horizontal wells could be carried out in approximately 30 days.

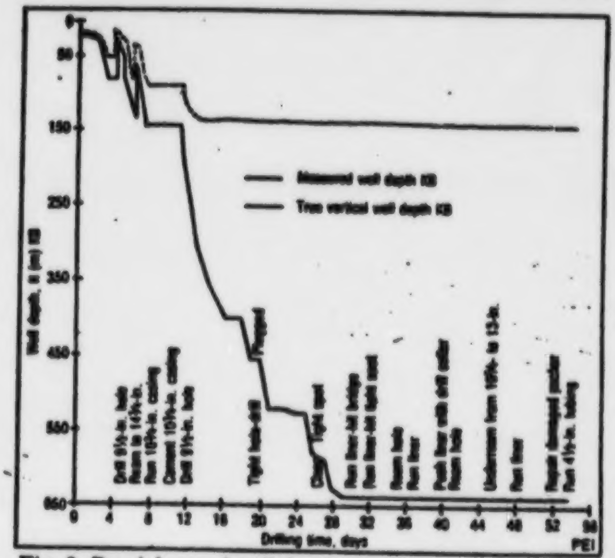


Fig. 9. Breakdown of well depth versus days for horizontal hole H3.

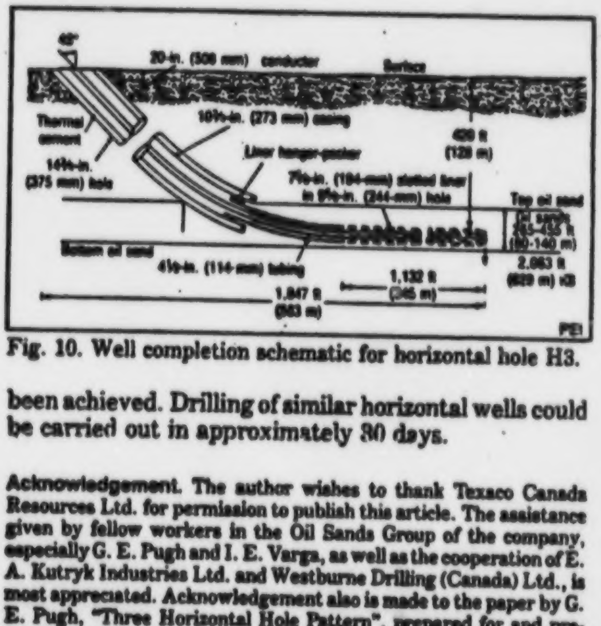
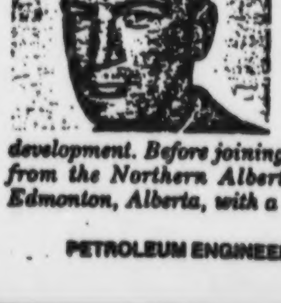

45°
20-in. (508 mm) conductor
Surface
Thermal cement
10¾-in. (273 mm) casing
14¾-in. (375 mm) hole
Liner hanger-packer
420 ft (128 m)
7⅝-in. (194-mm) slotted liner in 9⅝-in. (244-mm) hole
Top oil sand
Bottom oil sand
4½-in. (114-mm) tubing
1,132 ft (345 m)
1,847 ft (563 m)
2,063 ft (629 m) KB
PEI

Fig. 10. Well completion schematic for horizontal hole H3.

Acknowledgement. The author wishes to thank Texaco Canada Resources Ltd. for permission to publish this article. The assistance given by fellow workers in the Oil Sands Group of the company, especially G. E. Pugh and I. E. Varga, as well as the cooperation of E. A. Kutryk Industries Ltd. and Westburne Drilling (Canada) Ltd., is most appreciated. Acknowledgement also is made to the paper by G. E. Pugh, "Three Horizontal Hole Pattern", prepared for and presented at the 2nd International Conference on Heavy Crude and Tar Sands, Caracas, Venezuela, Feb. 7-17, 1982.

About the Author



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FORT KENT THERMAL PROJECT - INNOVATION BEATS THE ODDS

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Alberta OIL SANDS
INFORMATION CENTRE

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FORT KENT THERMAL PROJECT - INNOVATION BEATS THE ODDS

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ABSTRACT

Non-conventional heavy oil (oil too viscous to produce without thermal stimulation) is becoming an important source of Canadian oil production. This paper describes Suncor's Fort Kent Thermal Project, one of the few economically viable projects of its type and size in Canada. The location and nature of this project have necessitated several unique developments.

The Fort Kent project began pilot development in 1975 and in 1982/83 it was expanded to 635 m^3/d (4,000 BPD) with the expenditure of $64 million dollars.

This paper describes the expansion phase and the steps required to make the project socially, environmentally, technically and economically viable.

Two important innovative developments are described; the use of slant hole drilling and the use of municipal sewage effluent as source water for steam generation.

INTRODUCTION

The Fort Kent Thermal Project is termed a non-conventional heavy oil project. The in-place viscosity of the oil is such that it cannot be produced with natural reservoir energy. Thermal techniques such as steam injection to reduce oil viscosity are required to obtain oil production.

Non-conventional heavy oil projects have several inherent characteristics, most of which result in higher costs and greater technical difficulty compared to conventional heavy oil projects (i.e. those producible with natural reservoir energy or with conventional waterflood assist).

Non-conventional heavy oil projects are capital intensive. They are also people intensive and have high operating, fuel and maintenance costs. Such projects require the diligent application of engineering and other technical skills. The availability of sound mechanical technology is critical to success. The geology is often complex. Reservoir technology is not readily portable and is usually tailored to the specific reservoir through expensive field pilot testing. Environmental protection costs are high. Long term markets are uncertain. To be transported viscous heavy oil must be blended with diluent, the long term supply of which is uncertain. Lenghty lead times are required to find, delineate and pilot test deposits prior to commercial development. All of these factors tend to make the economics of heavy oil projects difficult or marginal. Industry is nevertheless motivated to pursue development of such heavy oil because of the huge available resource potential.

All of the foregoing characteristics are present at the Fort Kent Thermal Project. This paper discusses Suncor's experiences and some of the technical innovation and adaptation that overcame the inherent difficulties and has resulted in a successful project.

LOCATION

The Fort Kent Thermal Project is located on a 7-3/4 section oil sands lease about 11 km northeast of Bonnyville in Alberta. The area is a productive agricultural community and is also dotted with several small recreational lakes. There are 31 residences within or immediately adjacent to the Fort Kent oil sands lease.

HISTORY

A 17-meter (56 ft.) column of heavy oil was encountered at Well 6-28 in 1974 in the course of natural gas exploration by Worldwide Energy.(1) In 1975 a single well steam stimulation test was conducted. This pilot was expanded to 6 wells in 1975, to 21 wells (Phase I) in 1978 and to 37 wells (Phase II) in 1979, all on an approximate 2 hectares per well spacing. Suncor acquired a 50% working interest in 1978 and became project operator in 1980.

The project underwent a major expansion, Phase III, (fig. 1) in 1982/83 to the current 118 wells and 635 m^3/d (4,000 Bbls/day) capacity at a cost of 64 million dollars. The latter expansion is the primary subject of this paper.

The project illustrates the long lead times involved from discovery to full scale development.

GEOLOGY

The primary zone of interest at Fort Kent is the Cretaceous Upper Manville Waseca sand member. The Waseca sand is interpreted to be a near-shore river channel system (fig. 2) about 200 to 400 meters wide trending southwest across the lease. The middle of the channel exhibits excellent sand quality and good thickness with a maximum encountered oil sand thickness of 26 meters (89 feet). The oil sand quality and thickness rapidly deteriorates at the channel edges. Local structural lows may contain 1 to 2 meters of water column.

Secondary zones of interest, generally of lessor thickness and quality, are the Sparky and McLaren sands. The Sparky, which underlies the Waseca, and is often eroded by the Waseca, is interpreted to be an offshore bar complex.

The McLaren overlies the Waseca sand and is believed to be a fluvial channel system.

The Waseca, Sparky and McLaren members are detectable with the use of high resolution seismic techniques. Extensive seismic coverage was obtained across the channel on a .25 km (.16 mile) spacing. This spacing and Suncor's processing techniques allowed for the precise determination of the edges of the narrow Waseca channel and the determination of the gross sand thickness to within 2.5 meters. The development of the seismic techniques was an important factor in reducing the frequency of dry holes drilled in the Phase III expansion, resulting in an 82% drilling success factor.

RESERVOIR AND FLUID PROPERTIES

The following are the average Waseca reservoir and fluid characteristics at Fort Kent:

Overburden depth	335 m (1100 ft.)
Net Oil Pay	15 m (50 ft.)
Oil Saturation	74%
Porosity	33%
Permeability	1-4 darcies
Reservoir Temperature	13.3°C
Oil Viscosity at Reservoir Temperature	50,000 CP
API Gravity	12°
Sulphur	3.95 Wt.%

RESERVOIR PROCESS

Cyclic steam stimulation techniques are currently the primary means of production at Fort Kent. Typically 3,200 m^3 (20,000 bbls) of water are injected as 80% quality steam into the reservoir at wellhead conditions of up to 11,000 kpa (1,600 psia) and 310°C over a period of about three weeks. The well is allowed to steam soak for several days and is then produced for 3 to 6 months until the well fluids cool to about 50°C. At this point the well is re-steamed. Approximately 4 m^3 of water are injected and produced for each 1 m^3 of oil produced. The adaptation of steam policy to individual wells and the management of inter-well communication is the subject of continuous experimentation to maximize performance. Cyclic steam stimulation is expected to yield 22% recovery of the original oil in place.

A number of investigations are under way to improve the recovery and capitalize further on the fixed investment in place. Steam flooding has been tested on a five well pattern for two years and additional enhancements such as CO_2 injection and surfactants are being studied.

The well spacing of one well per 2 hectares (5 acres) appears near optimal.

PHASE III EXPANSION

Based on the interpretation of the Waseca channel geology available in 1980, the Phase III expansion was planned to increase oil production from about 160 m^3/d (1,000 bbls/day) to 800 m^3/d (5,000 bbls/d) with the drilling of 112 wells at a cost of $88 million dollars.

The project received conditional internal approval to proceed in January 1981, however, final regulatory approvals were not in place until March of 1982. Key regulatory components were negotiation of the application of 5% experimental Alberta royalty and the application of New Oil Reference Price (i.e. surrogate for world oil price) to the project.

Drilling started in March of 1982 followed by commencement of construction in May. By May of 1983 drilling was completed and the central facilities had been commissioned.

Because the Waseca channel proved to be more confined than anticipated, the project was downscaled from the planned scope to 82 completed wells and a capacity of 650 m^3/day (4,000 bbls/day) at a completed cost of $64 million dollars.

COMMUNITY RELATIONS

Heavy oil development, although it promises some positive benefits to a community in terms of employment opportunity and increased economic activity, has many perceived negative impacts.

It became clear that the environmental and social aspects of the proposed expansion would need to be very thoroughly addressed to gain community acceptance and regulatory approvals.

The first step in the process was to incorporate technical innovation and improvements into the expansion design to alleviate some of the key negative impacts.

The most important impact was perceived to be the issue of land use. The 37-well development on 2-hectare vertical well spacing then in place essentially removed the total surface area, about 75 hectares (185 acres), completely out of agricultural use. The area had become a network of surface pipelines, roads, power lines, well locations and central facilities. This adverse feature was mitigated through the development of cluster slant hole drilling which will be discussed further.

Water for steam production for the pilot activities was available in limited quantities from shallow subsurface wells. The practice was to inject steam, produce back oil and water, and to dispose of the produced water into a horizon below the productive sands. The proposed expansion required up to 3,200 m^3/day water (20,000 bbls/day). Clearly the use of shallow subsurface water in such volumes was unacceptable due to the potential adverse impact on the area's ground supply. A solution was developed whereby the use of sewage effluent from the Town of Bonnyville together with produced water re-use and backup ground water provided adequate water for the project. Thus a potential negative environmental impact was turned into a positive benefit to the area.

Numerous other social and environmental impacts were considered and solutions were developed to the best practical degree.

At this point a concerted communication effort was initiated to explain the proposed developement to the community. Care was taken to ensure that all potential publics were addressed. Particular attention was paid to the needs and concerns of the immediate residents in the Fort Kent area.

The communication program was successful as evidenced by the fact that when the governing Alberta regulatory body, the Energy Resources Conservation Board, advertised for objections to the proposed expansion, not a single objection was received.

The communication effort is an ongoing activity. The promised employment and spin-off benefits did occur and are still occuring. The construction workforce peaked at 350 of which about 80% came from local communities. Some 70 local businesses participated in the construction effort. The Canadian content of purchased goods was above 80%. The ongoing workforce is 60, the majority of which are of local origin.

SLANT HOLE DRILLING

Land use considerations dictated the surface location of wells in clusters. It is not uncommon to develop oil pools using deviated wells from small surface areas, both onshore and offshore. Normal practice is to drill vertically to surface casing depth and then, using a variety of directional techniques to deviate the wellbore to its desired target.

In the case of Fort Kent, the shallow, 350 m, depth of the reservoir precluded the use of the standard cluster drilling technique. To develop a sufficient subsurface area on 2 hectares (5-acre spacing), a high angle build rate (up to 5°/30 m) would be required resulting in an unacceptable bottom hole angle (up to 84°). It was therefore decided to drill the surface hole at an angle and deviate to the bottom hole target as required. The advantage that slant drilling has in reaching out horizontally is illustrated in fig. 3.

A typical cluster development plan, shown in fig. 4, permits drilling of 32 wells on 2 hectares (5-acre spacing), thus potentially developing 65 hectares (160 acres) from a 4-hectare (10-acre) pad. Because of the confined channel reservoir at Fort Kent, the largest number of wells actually drilled from a single cluster location was 26.

Slant drilling rigs are used extensively in offshore development in Peru and to some extent in offshore California to tap shallow reservoirs, however, the concept had not been used to date for heavy oil development. A modified version of a variable angle rig successfully used on offshore platforms in Peru was constructed for the project at a cost of $5.4 million dollars (fig. 5). The rig is diesel-electric powered and fully winterized connected by a utilador to the mud, heating and electric power systems. The slant derrick is capable of movement from vertical to 35° in 5° increments. The vertical mast used is for racking pipe. The rig was designed to drill continuously and is able to move intact on rollers over rig mats from location to location on the cluster or between clusters. Noise reduction in consideration of area residents was a factor in choosing diesel-electric power.

All wells are thermally cased. A typical completion is illustrated in fig. 6.

The drilling system performed above expectations and improved with experience (fig. 7). The overall average time requirement for 100 wells drilled was 4.01 days/well including moving time. The average time for the last 80 wells was 3.75 days/well.

In addition to the slant orientation, additional deviation through directional drilling was required to hit acceptable bottom hole targets. These were defined as 10 meters in radius. Other constraints were the maximum angle build-up should not exceed 3°/30 m, and that the maximum hole angle at the bottom hole target would be 45°. Experimentation with the initial 16 wells to develop standard techniques to consistently meet the constraints using bottom hole assemblies and rotary methods proved unsuccessful. The remainder of the wells were drilled using a kick sub and a downhole motor. This method resulted in a smoother hole and good drilling times, with 90% of the wells within the acceptable target range.

No undue difficulties were experienced with borehole logging, except on wells with deviation angles exceeding 45°, nor with completion procedures. The wells were perforated and in most cases were equipped with sand screens to control formation sand influx.

To compliment the slant wells, slant pumpjacks were designed to accommodate the required geometry and a slant service rig was developed to service the wells. The producing wells are performing satisfactorily. Rod fall, however, in the viscous heavy oil is more pronounced than in vertical wells and requires slightly earlier resteaming of wells.

A full description of the application of slant drilling to Fort Kent may be found in the referenced paper by Hart and Jankowski (2).

WATER SUPPLY - SEWAGE EFFLUENT AND REUSE

Approximately 4 m^3 of water as steam are required to produce 1 m^3 of oil. The Fort Kent project was thus planned to use 3,175 m^3 (20,000 bbls) of water/day for steam generation. The water supply was identified as primarily sewage effluent from the Town of Bonnyville. The design incorporated limited reuse of produced water.

Once through 50 MMBTU/HR steam generators located at cluster sites are used at the project to generate 80% quality steam. The feed water specifications are as follows:

Oil	1	mg/L
Hardness	0.1	mg/L
Oxygen	0.04	mg/L
Silica	50	mg/L
Iron	0.05	mg/L
Total Dissolved Solids	7,000	mg/L
Turbidity	Near Zero	

To meet the above specifications economically with a blend of municipal effluent and produced water required an extensive and sophisticated water treatment plant. The process flow schematic is illustrated in fig. 8. The use of municipal water requires careful control of organic growth through chlorination. The produced water must be completely deoiled. Produced water at Fort Kent has a total hardness of 1,800 mg/L, TDS 13,500 mg/L and a silica content of 150 to 250 mg/L and thus requires significant softening and silica reduction.

The blending ratio of municipal water to produced water has been designed to eliminate the need for silica removal and to enable most of the hardness to be removed by warm lime softening and ion exchange. The key limiting factor is silica. With the system, 20% and possibly up to 50% water reuse may be economically achievable. A complete discussion of the use of municipal water and water reuse at Fort Kent is available in the referenced paper by Lackey, Fulton and Vaughan (3).

The plant has performed satisfactorily at up to 30% produced water reuse. Its economical limitations to reuse produced water have yet to be determined.

PRODUCTION TREATMENT

Pipeline specifications for marketing heavy oil require BS&W (basic sediment and water) content below 0.5%. At Fort Kent this accomplished by parallel production treatment trains consisting of desand vessels, free water knockout vessels, production heaters and coalescer (fig. 9). Particular attention is paid to heat recovery and management at these facilities and throughout the project site.

In spite of the minimal difference in density between produced water and oil, production treatment to pipeline specifications is being accomplished without the use of diluent. Special attention is being given to problems associated with fine formation sand produced with the oil which causes erosion and accomulates in vessels and tanks.

OTHER FACILITIES

Other important facilities at Fort Kent include production testing units, steam and production manifolds, utiladors, annulus gas recovery units, vapour recovery units, glycol heat exchange and pipe tracing, fuel supply (natural gas), a sand collection pit, a lime sludge pond, water disposal facilities and a significant amount of tankage. All facilities must be carefully insulated to prevent fresh water freeze-ups.

CONCLUSION

The Fort Kent Thermal Project is an example of a small but viable non-conventional heavy oil project. The inherent difficulties associated with non-conventional heavy oil projects in this case were overcome through innovation and adaptation of technology and sound engineering design.

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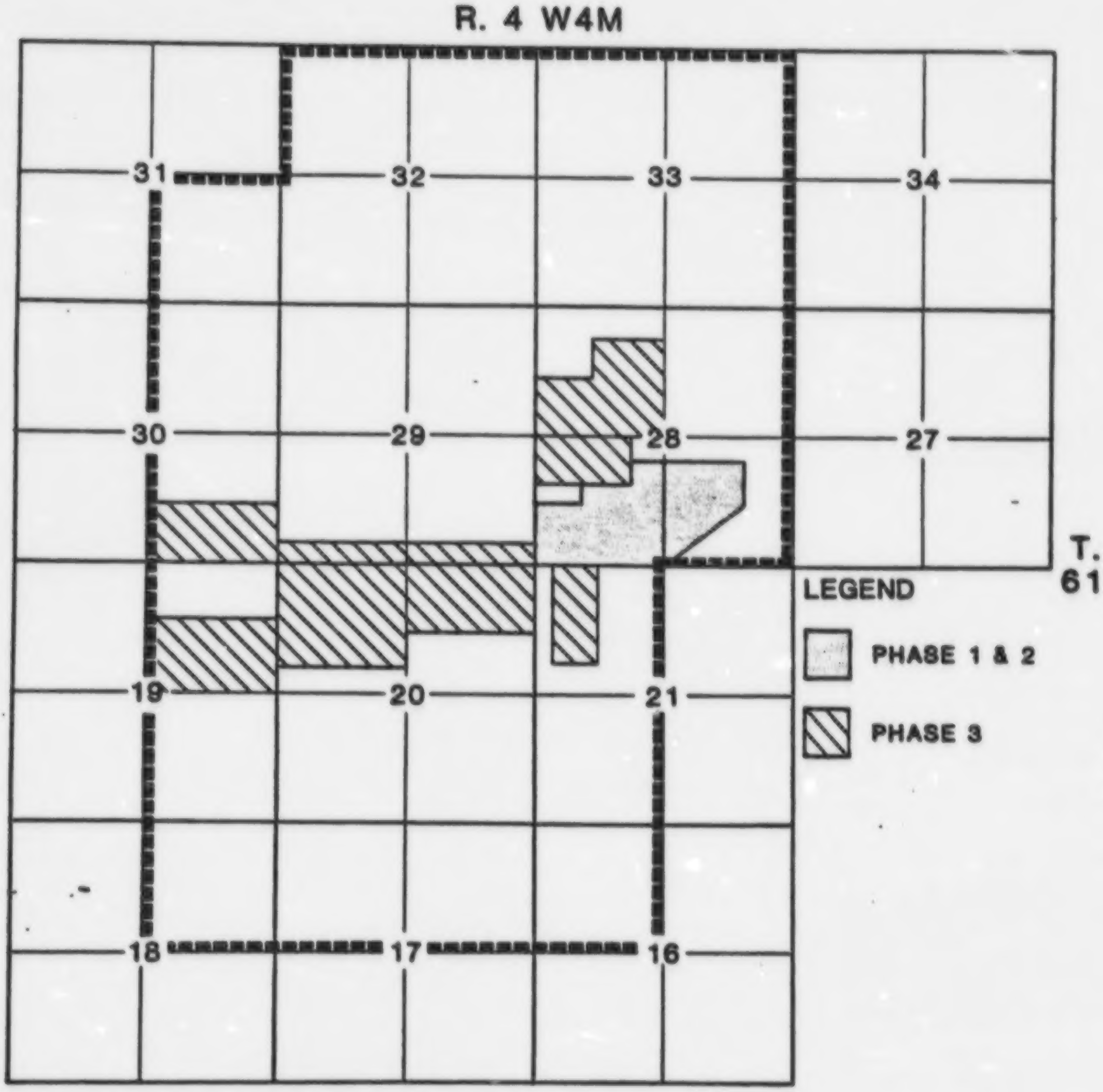
(2) HART, K. W. and JANKOWSKI, L. V., The Application of Slant Hole Drilling in Development of Shall Heavy Oil Deposits, JCPT, January - February 1984.

(3) LACKEY, S. L., FULTON, C. S. and VAUGHAN, D. A., Conjunctive Use of Produced Water and Municipal Wastewater to Generate Steam for Tertiary Oil Recovery, Water Reuse Symposium II, August 1981, Washington, D.C.


R. 4 W4M
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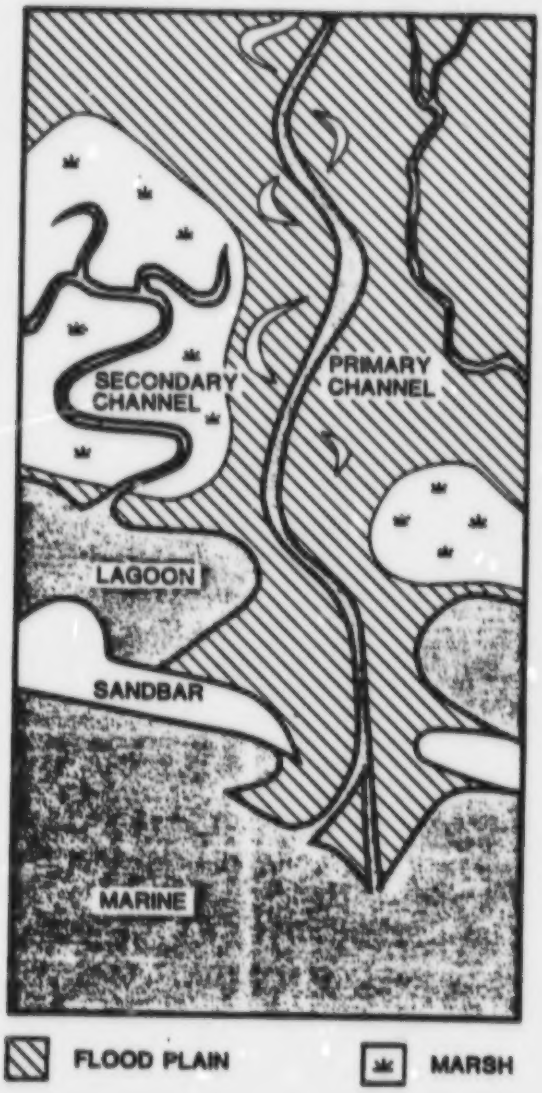
LEGEND
PHASE 1 & 2
PHASE 3

Fort Kent Thermal Project
Heavy Oil Development

FIGURE 1

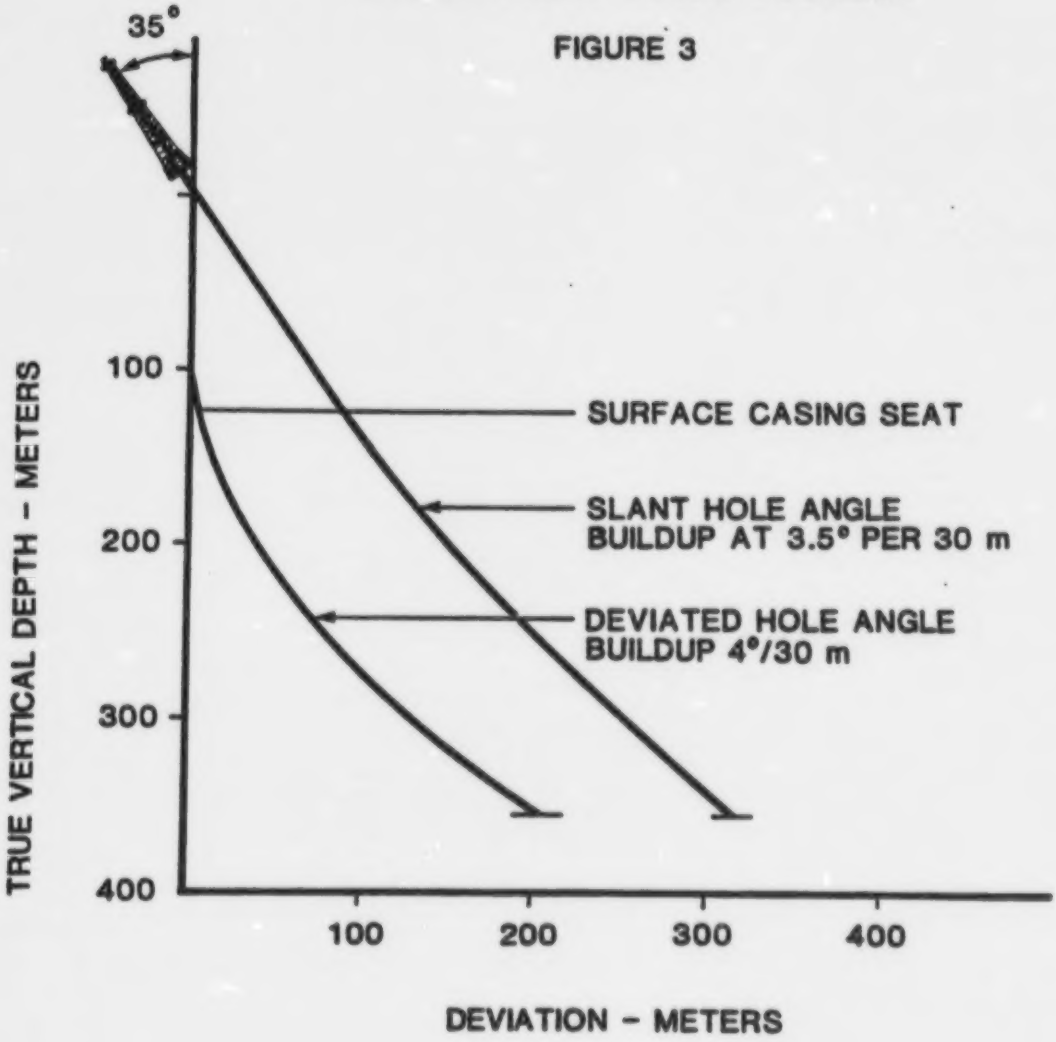

SECONDARY CHANNEL
PRIMARY CHANNEL
LAGOON
SANDBAR
MARINE
FLOOD PLAIN
MARSH

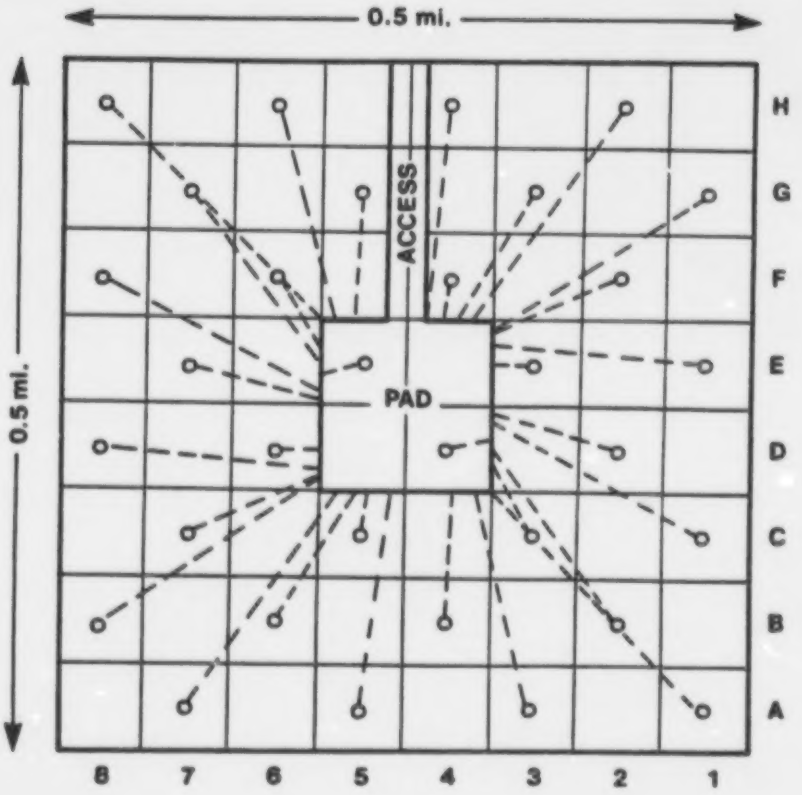
Fort Kent Geology Schematic

FIGURE 2

Comparison Deviated Versus Slant Hole Profiles

FIGURE 3




0.5 mi.
0.5 mi.
ACCESS
PAD
H
G
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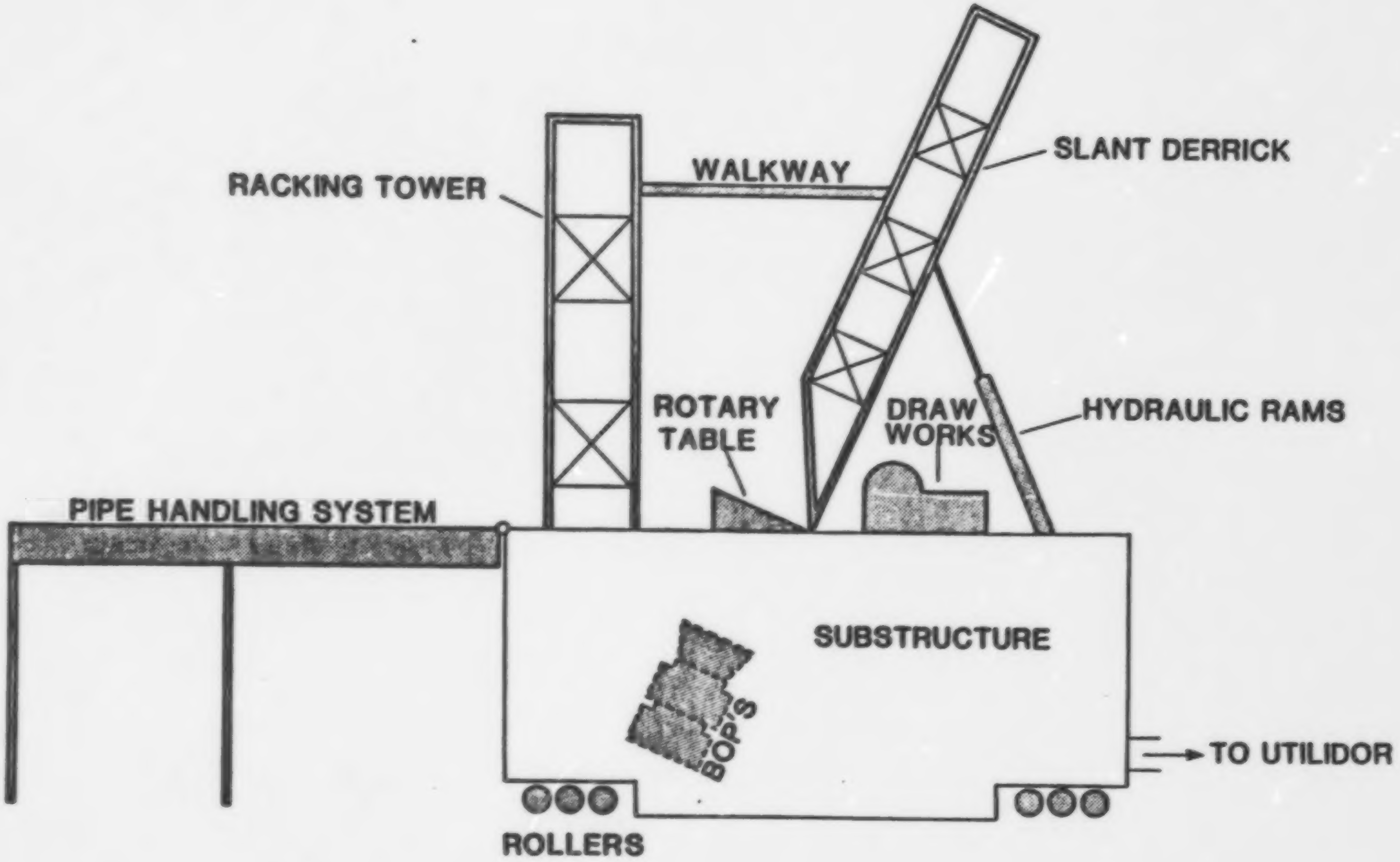
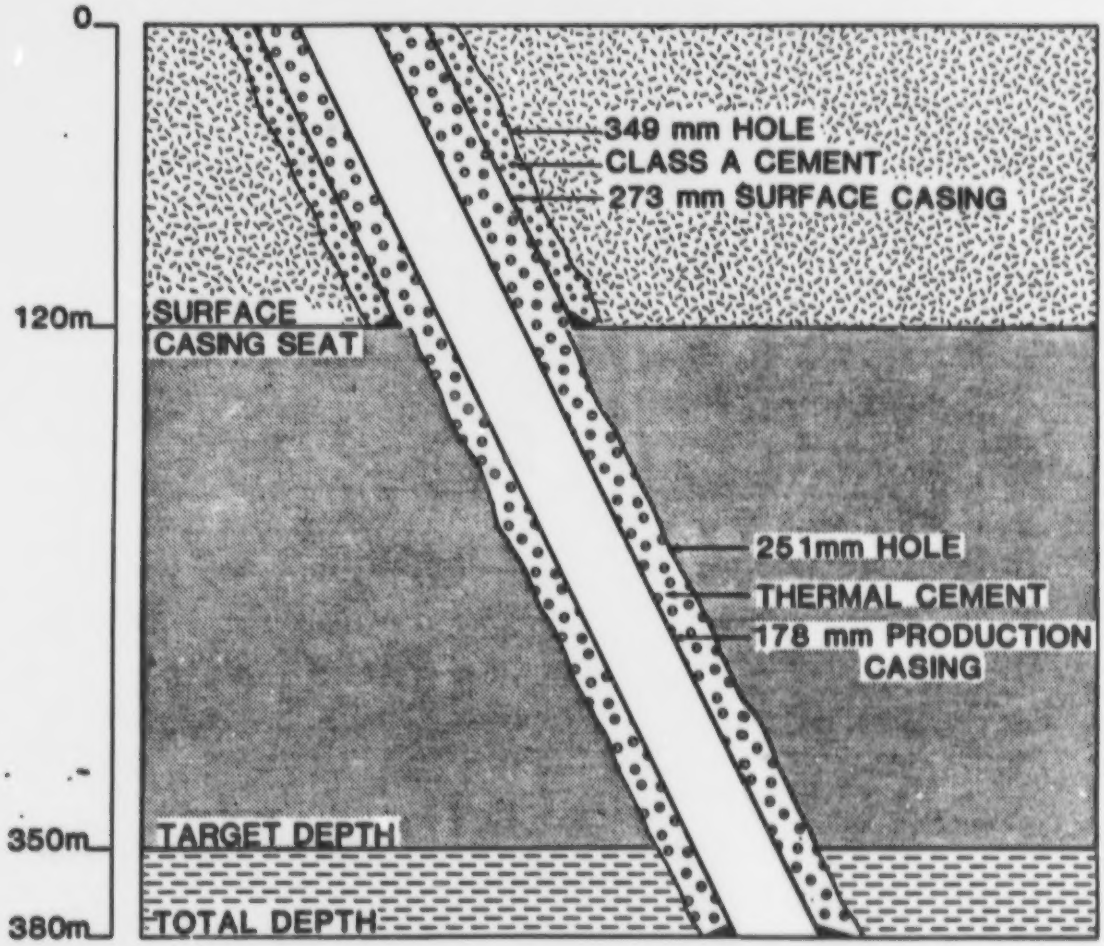
Quarter Section Well and Pad Configuration

FIGURE 4


RACKING TOWER
WALKWAY
SLANT DERRICK
ROTARY TABLE
DRAW WORKS
HYDRAULIC RAMS
PIPE HANDLING SYSTEM
SUBSTRUCTURE
BOP'S
TO UTILIDOR
ROLLERS

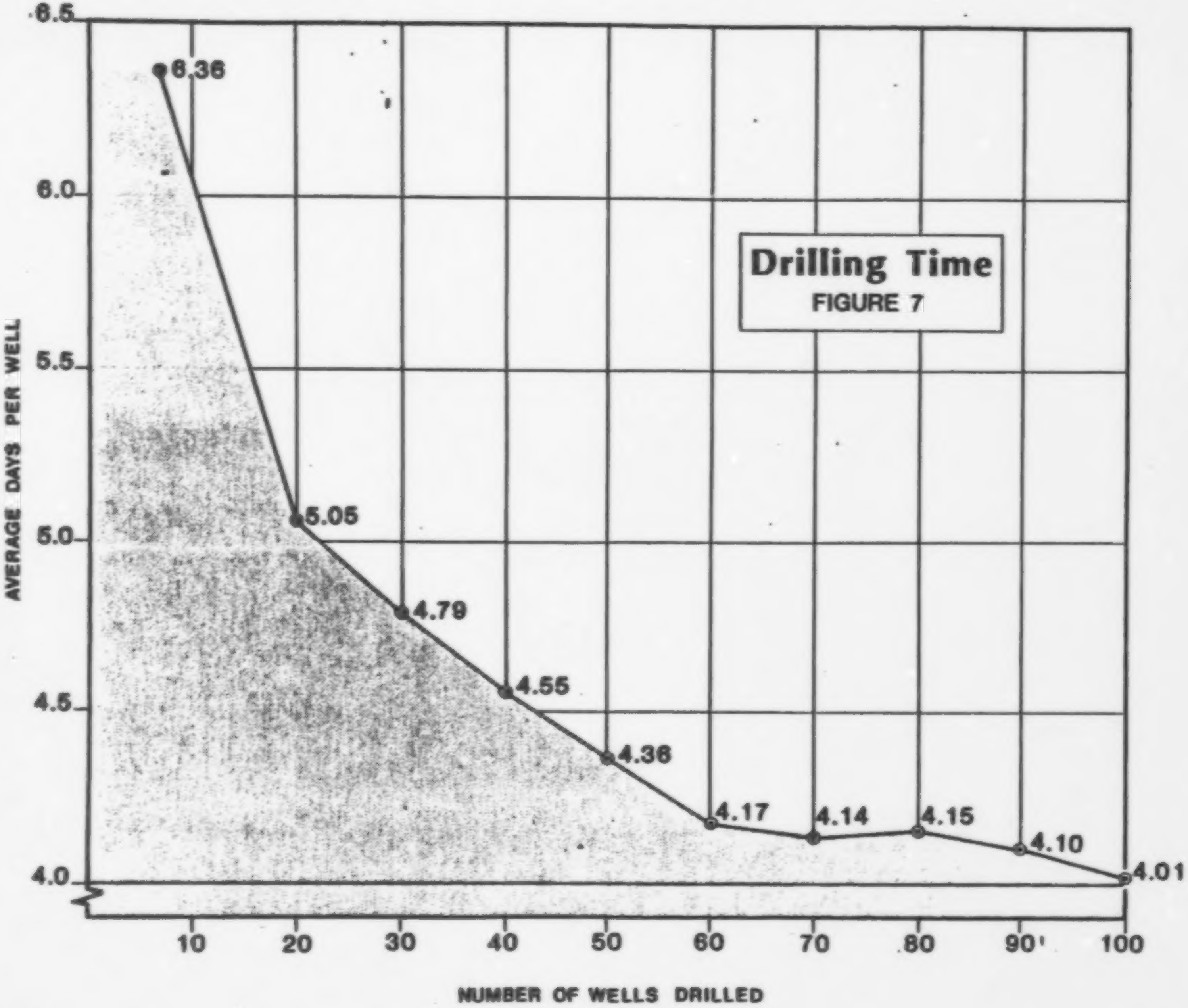
Drilling System

FIGURE 5


0
349 mm HOLE
CLASS A CEMENT
273 mm SURFACE CASING
120m
SURFACE
CASING SEAT
251mm HOLE
THERMAL CEMENT
178 mm PRODUCTION
CASING
350m
TARGET DEPTH
380m
TOTAL DEPTH

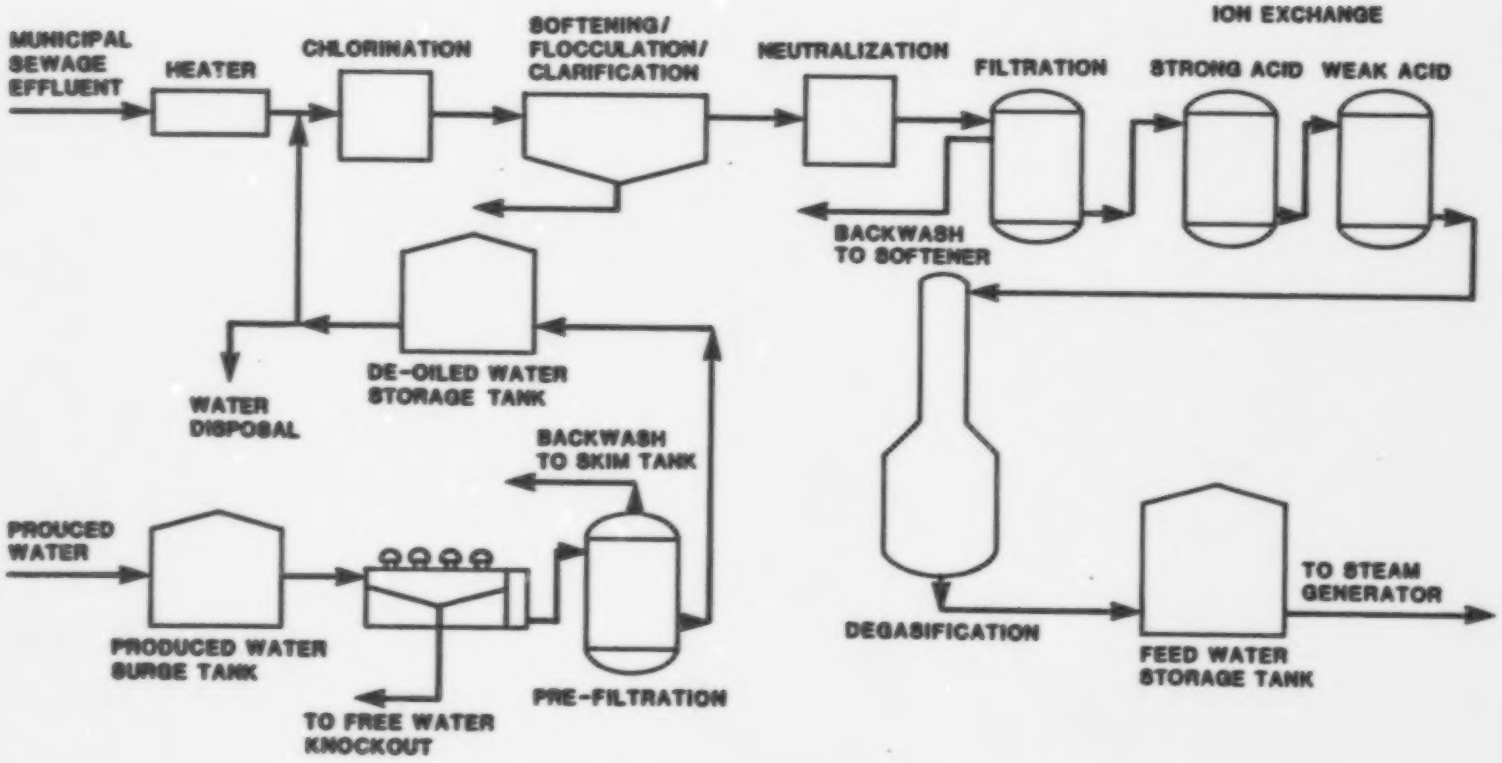
Well Diagram

FIGURE 6



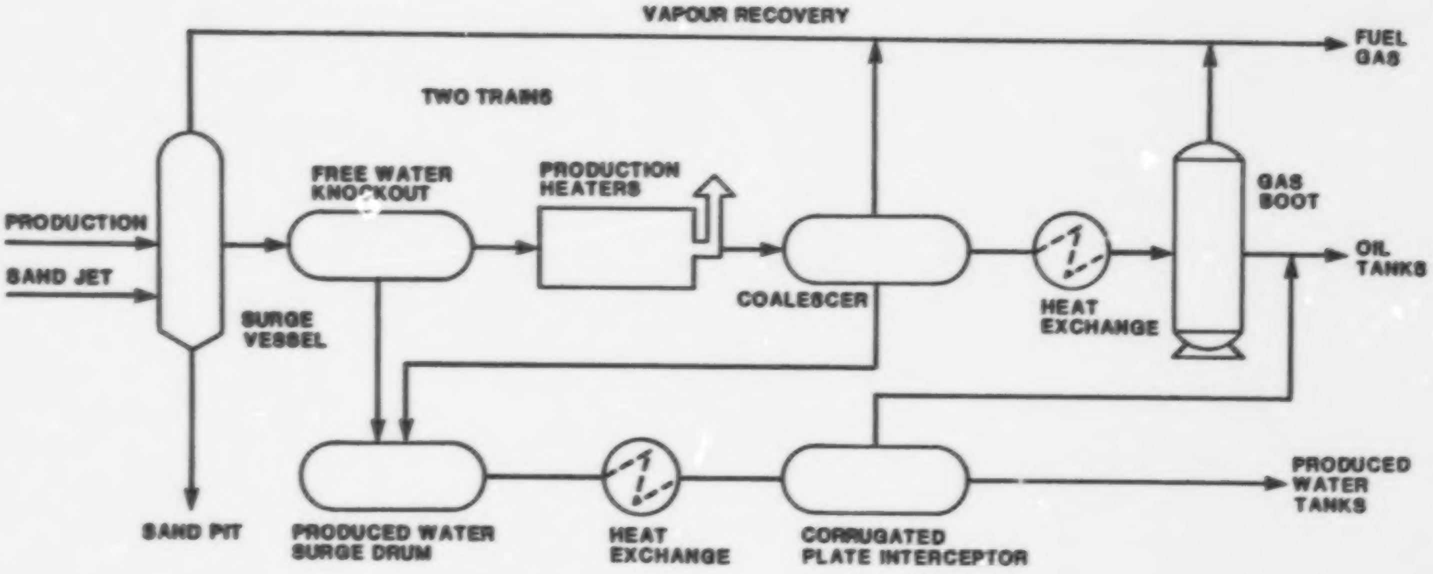
Drilling Time

FIGURE 7


MUNICIPAL SEWAGE EFFLUENT
HEATER
CHLORINATION
SOFTENING/ FLOCCULATION/ CLARIFICATION
NEUTRALIZATION
FILTRATION
ION EXCHANGE
STRONG ACID
WEAK ACID
BACKWASH TO SOFTENER
WATER DISPOSAL
DE-OILED WATER STORAGE TANK
BACKWASH TO SKIM TANK
PROUCED WATER
PRODUCED WATER SURGE TANK
TO FREE WATER KNOCKOUT
PRE-FILTRATION
DEGASIFICATION
FEED WATER STORAGE TANK
TO STEAM GENERATOR

Water Treatment Process Schematic

FIGURE 8


VAPOUR RECOVERY
FUEL GAS
TWO TRAINS
PRODUCTION
SAND JET
SURGE VESSEL
FREE WATER KNOCKOUT
PRODUCTION HEATERS
COALESCER
HEAT EXCHANGE
GAS BOOT
OIL TANKS
SAND PIT
PRODUCED WATER SURGE DRUM
HEAT EXCHANGE
CORRUGATED PLATE INTERCEPTOR
PRODUCED WATER TANKS

Fort Kent Production Treatment

FIGURE 9

009432

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INTRODUCTION AND DEVELOPMENT OF THE TILT RIG

With the increased pace of insitu development of heavy oil in north eastern Alberta, we at North Eastern Drilling recognized some years ago that a need existed for specialized drilling equipment to undertake this work more economically under certain adverse conditions of terrain and formation, and within regulatory constraints.

At that time Suncor Inc., an industry leader in heavy oil development, had done considerable engineering towards developing heavy oil extraction based on the concept of cluster drilling. This was their Fort Kent Project in the heavy oil deposits around Cold Lake in north central Alberta.

This project required a drilling rig that would drill variable angle holes, with deviation starting at the surface rather than the conventional directional wells under surface casing. North Eastern, therefore, as a first step to developing a rig for this application, investigated areas where that type of drilling had been done elsewhere in the world.

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Slant hole drilling had been pioneered and developed off the coast of Peru since 1966 by Belco Petroleum Corporation. Belco Petroleum Corporation anticipated problems in their Peruvian venture not only in drilling, but also in servicing and producing the wells economically. The low bottom hole pressures in the shallower depth wells would normally have made it necessary to plan for some method of artificial lift early in the life of each well. A true vertical depth of from less than 200 metres to 1700 metres severely limited the number of wells that could be drilled from one jacket by conventional drilling methods. Normally four wells on each jacket could be anticipated and then only by building angles at a very high rate. This procedure would have made it necessary to construct numerous small structures thereby creating additional expense and technical problems in laying flow lines, aids to navigation, transfer pumps, separators and obvious maintenance requirements and associated burdens. Additionally, the size of these structures was inadequate to accommodate the proper producing and servicing equipment and would have made it mandatory to employ expensive mobile servicing units for remedial work.

A new method was conceived and perfected in 1966 in a joint effort with the operator which cut the cost normally associated with the use of conventional jackup and platform type drilling rigs. The joint effort resulted in the design and manufacture of a special application rig capable of spudding and drilling bore holes at a maximum surface angle of thirty degrees then building angle by conventionally controlled methods of up to seventy degrees maximum angle.

Approximately 1,000 wells have been drilled in the Peruvian Pacific Area utilizing the Variable Angle Drilling Rigs. Only one well on each platform was spudded vertically. The subsequent wells were spudded at various angles up to thirty degrees and actually were increased during drilling to as much as seventy degrees. The high average angle maintained made it possible to effectively drain an area sufficient in size to accommodate nineteen wells on a single platform. No mechanical problems have been encountered which would tend to limit the depth that can be drilled.

Belco found that the Variable Angle Drilling Rig is a unique, versatile rig particularly adaptable to relatively shallow to medium depths where available drill sites are either limited in number or extremely expensive. This would include offshore and certain urban areas. While no depth limitation is apparent in drilling by this method, it is concluded that utilization of the Variable Angle Drilling Rig at depths above 2600 metres true vertical is the most practical application.

North Eastern entered into a series of technical exchanges with Suncor engineers during 1980, which included a visit to Peru to observe the platform operation.

In February of 1981, North Eastern was awarded a contract by Suncor to construct and operate a slant drilling rig (maximum 35° spud angle) for their Fort Kent Project. Not only would this be the first slant rig using conventional control methods for cluster drilling on land, but it would be a rig totally designed and custom built for pad drilling.

The resultant drilling rig was North Eastern Tilt-Rig No. 1, a variable angle rig employing both conventional equipment and specially designed components with modifications compatible to conventional practice. In Tilt Rig No. 1, North Eastern has developed an innovative design, incorporating the newest technology into many features. Pipe movement and racking, power tongs, conventional rotary table adaptations for high speed, high angle drilling, self contained rig mobility, and an innovative centralized support system, are all designed for high productivity (See Picture).

The rig has proven to be versatile and easy to operate in both conventional vertical and slant hole modes. For example, drill pipe is hoisted from the rack and laid in guides in the tilt mast, which aligns the joints precisely. This makes for ease and speed in make-up of joints, and greatly reduces thread damage. Movement of the rig on the pad is simple, and with hydraulically operated rollers and built-in winches, is achieved independently of any outside services. The centralization of support systems facilitates this since only the rig itself has to be moved.

Directional drilling is simplified because the well is spudded towards its target; it is only necessary to maintain direction and build or drop angle as necessary. A gradual and continuous build-up of angle is controlled principally by the use of conventional bottom hole assemblies and/or down-hole motors. On the Fort Kent Project minimal wear on drill pipe and drill collars was experienced and North Eastern drilled approximately 53,000 metres of hole with no measurable wear of the drill pipe joints. The gradual build-up of angle also minimizes production and well servicing problems (see Figure 1).

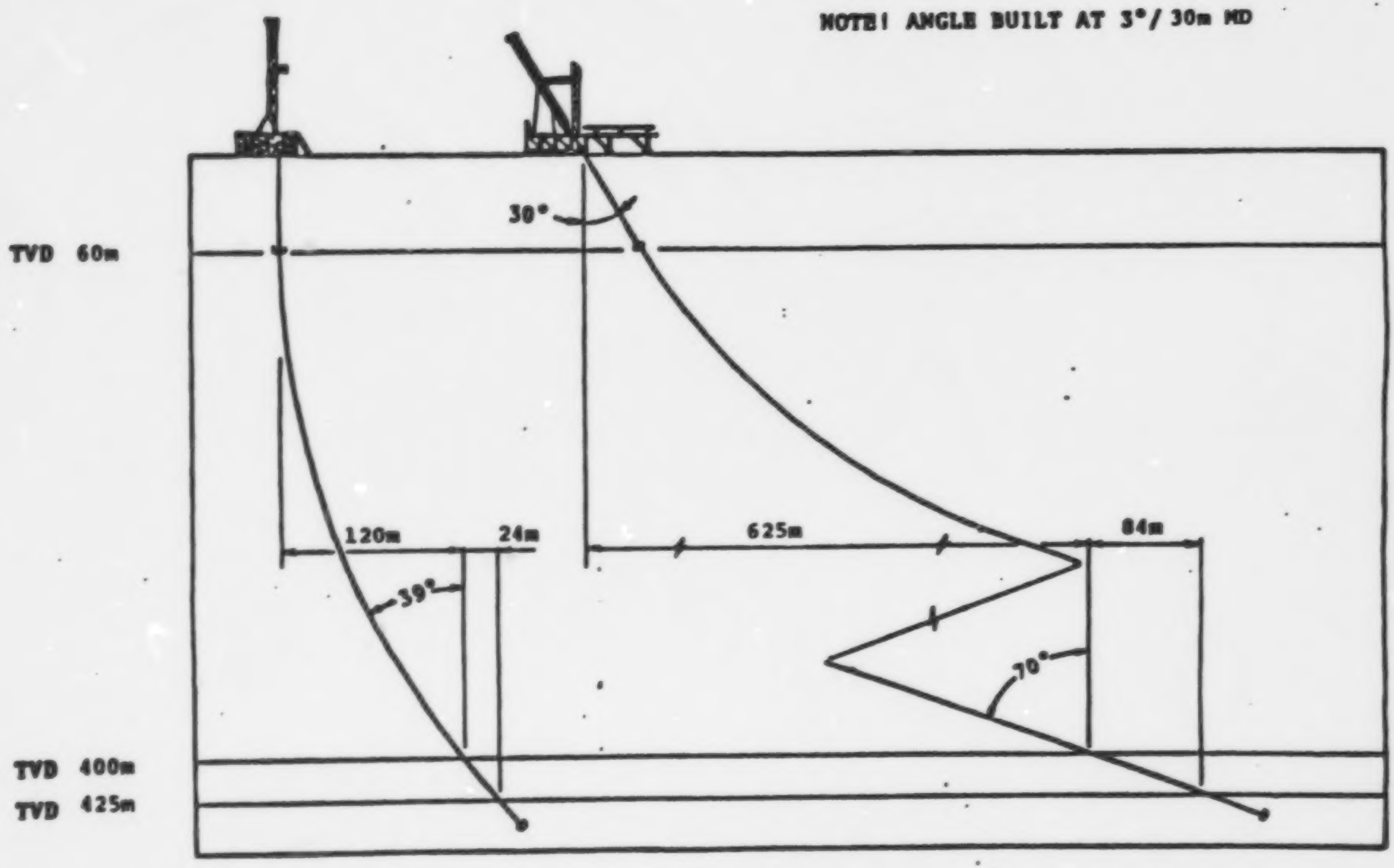

NOTE! ANGLE BUILT AT 3°/ 30m MD
30°
TVD 60m
120m
24m
39°
625m
84m
70°
TVD 400m
TVD 425m

FIG.1 - CONVENTIONAL DIRECTIONAL DRILLING VS SLANT - RIG DRILLING.
MUCH GREATER ANGLE CAN BE OBTAINED AT TARGET DEPTHS.

PROSPECTIVE APPLICATIONS

By permitting greater departures from vertical, the slant hole technique has a number of applications, and the cluster drilling concept can add to these. Some of the major applications are the drilling of inclined wells to formations located beneath areas such as the following:

- lakes and major rivers; slant holes avoid the need to drill off platforms or artifical islands.

- swamps and muskeg; targets can be reached from adjoining lands, or, cluster drilling greatly reduces access requirements in the difficult ground conditions.

- urban areas can be drilled with minimum disturbance.

- agricultural land is conserved to the maximum possible extent.

- parks, public lands, and productive forests overlying formations need suffer no disturbance, or only minimal environmental impact.

- environmentally sensitive areas generally can be preserved.

- the drilling of wells under industrial complexes, airports, railway marshalling yards, harbours, and similar areas is now possible with minimal disturbance.

- coastal offshore areas can be reached from onshore.

- in underground coal seams, horizontal drilling can be used to drain methane gas, both as a safety precaution and to produce the gas for commercial use.

SOME ADVANTAGES AND APPLICATIONS OF SLANT DRILLING

There are a number of advantages offered by slant drilling. Essentially these relate to increasing production by reaching target areas unattainable, or very difficult, by conventional means; achieving production earlier because of easier drilling conditions, and maintaining production of wells in areas of difficult access by drilling from adjoining better ground, or by cluster drilling thus servicing many wells from one access route and service pad.

Difficulties in access to drilling locations can be reduced or avoided completely. Wells which by conventional means may have been very difficult or impossible to drill, and then perhaps possible to service only on a seasonal basis, can now be drilled and serviced year round. Hence, production can be increased, and production is no longer lost due to inability to service wells to which access is denied by seasonal terrain conditions. Some major advantages are described in the following:

Economic Advantages:

- By spudding the hole at an angle, better directional control is achieved.

- The rate of building angle down hole is reduced, and this lessens the risk of down hole problems and delays due to doglegs forming of key seats.

- A much greater departure from vertical can be achieved for a given true vertical depth.

- In drilling directional holes, the slant technique allows for faster penetration rates.

- Areas previously inaccessible due to adverse ground conditions, or other restraints, can be approached from adjoining lands.

- Where drilling has to be performed in adverse ground conditions, a number of wells can be drilled to proper spacings at target depth from one drilling pad. This cluster drilling concept has the following advantages;

    o A single access route serves a number of wells, therefore, per well, road construction time and cost is considerably reduced, rig moving time is less, and site reclamation is reduced in time and effort.

- Production facilities can be centralized, with consequent savings in cost and easier operation, and production can be maintained throughout the year as long as the single access route is passable to well servicing equipment.

- Land occupied by the cluster is much less than that taken up by the same number of single wells, for both drilling and production.

- The risk of pollution by mud spillage and dumping of cuttings is confined to one site, rather than spread over the land in many locations.

PERFORMANCE OF NORTH EASTERN TILT RIG NO. 1

The North Eastern Tilt Rig No. 1 performed most successfully on the Suncor Fort Kent heavy oil project in east central Alberta.

The depth of the oil sand at Fort Kent is approximately 350m. The average deviation angle required to hit bottom hole targets from the pad as shown in Figure B-2 varies from 5° to 47.5°. Taking the extreme example, if the corner wells were spudded vertically, an angle build rate of 5°/30m and a bottom hole angle of 84° would be required to reach the targets. Since this is not feasible at this depth from vertical spudding, either additional pads would be required, resulting in more wasted farmland and higher project costs, or the wells would have to be spudded at an angle. Suncor considered the second approach more desirable and decided to pursue the slant-hole method.

The North Eastern rig design selected for the project was a modified version of the variable angle rig that was being successfully used on off-shore platforms. In order to adapt the concept to the intended land use, many modifications, and innovations were designed by North Eastern.

In addition to savings in drilling costs, the cluster concept enabled steam generation and production facilities to be centralized at the pads, and pipelines and access roads to be considerably reduced. Furthermore, well servicing is greatly simplified by the cluster arrangement inasmuch as many wells can be serviced from one pad.

SUPPLY OF A SLANT HOLE RIG

Variable angle rigs may be custom built to suit an operator's specific requirements. Such a rig should provide the versatility of both conventional vertical-spudded directional drilling and slant hole drilling up to a spud angle of 45°; and be equipped to ensure ease of mobility on a drilling pad, and between pads. In soft ground conditions, this system of rig moving permits drilling to proceed with little restraint throughout the spring thaw and summer seasons. If extensive rig moves are expected, the design can be adapted for even greater portability, to facilitate such extended moves.

The power system used on the North Eastern slant hole rig is diesel-electric with silicon rectifier (SCR) controls, which has proven to be efficient and economical for powering this drilling rig. However, other power systems can be implemented if desired. It is appropriate to note that on the Suncor project extensive measures were taken to reduce engine noise to minimize disturbance to people, livestock, and wildlife in the working area.

Another environmental feature is the mud system, which, for the Fort Kent Project, had to minimize dumping and, hence, maximize solids control and reuse of drilling fluids. This, along with the cluster drilling pattern, caused North Eastern to centralize the mud system. As described in Figures A-2 and A-3, the mud pumps, mud cleaner and centrifuge, and shale shaker are located with the power plant and ancilliary buildings all together in the centralized support system. An operator may require some variation of this centralized system, or a more conventional mud system, and this could be included in the design of the rig.

Rapid advances are being made in the areas of downhole monitoring and control, and in the development of directional tools and technology. Variable angle drilling can no longer be considered experimental.

An essential element in the whole concept of slant drilling is the capability to service wells that have been drilled. North Eastern has designed and is constructing a slant service rig so as to provide a complete service to industry.

Drilling System

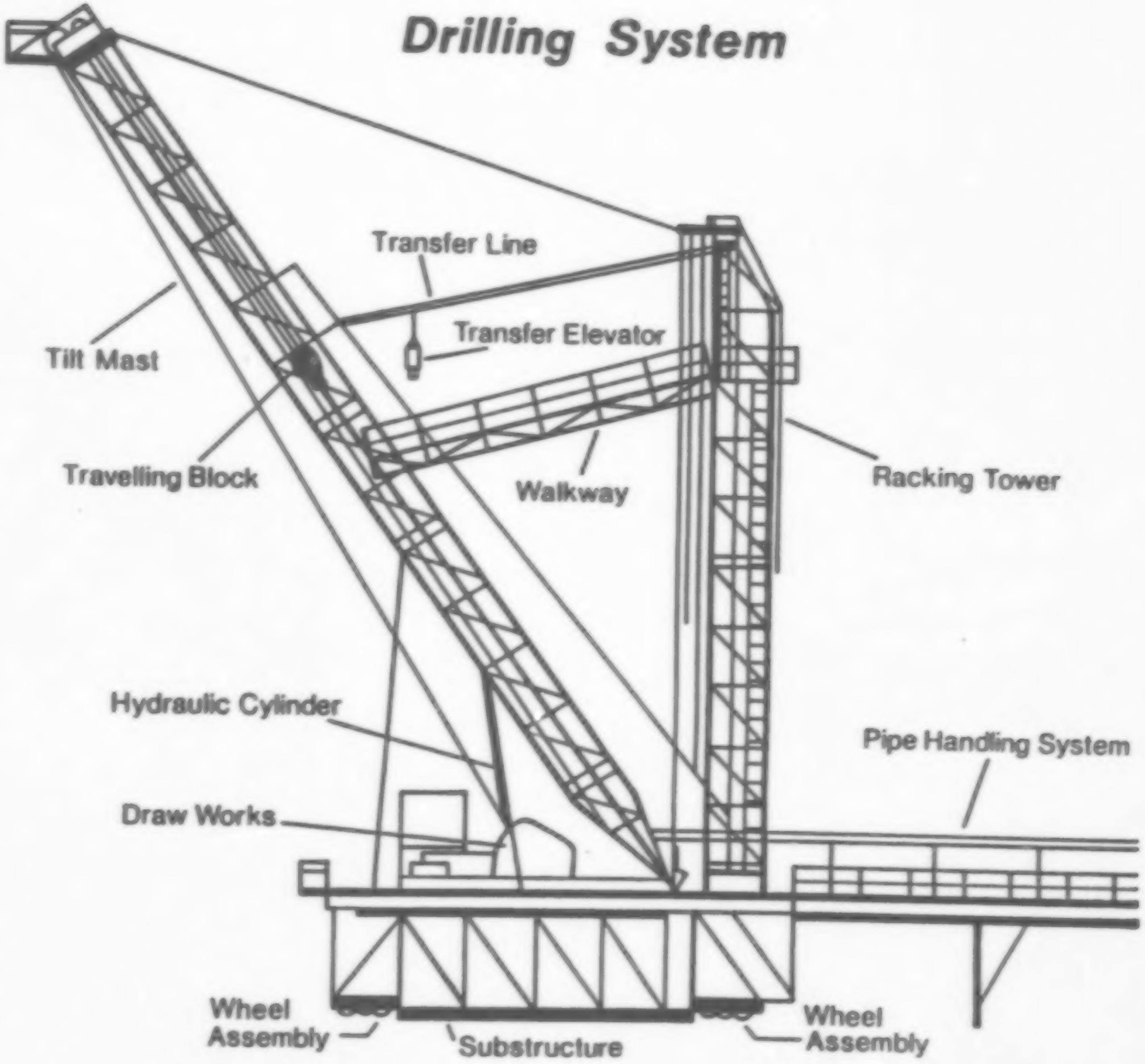
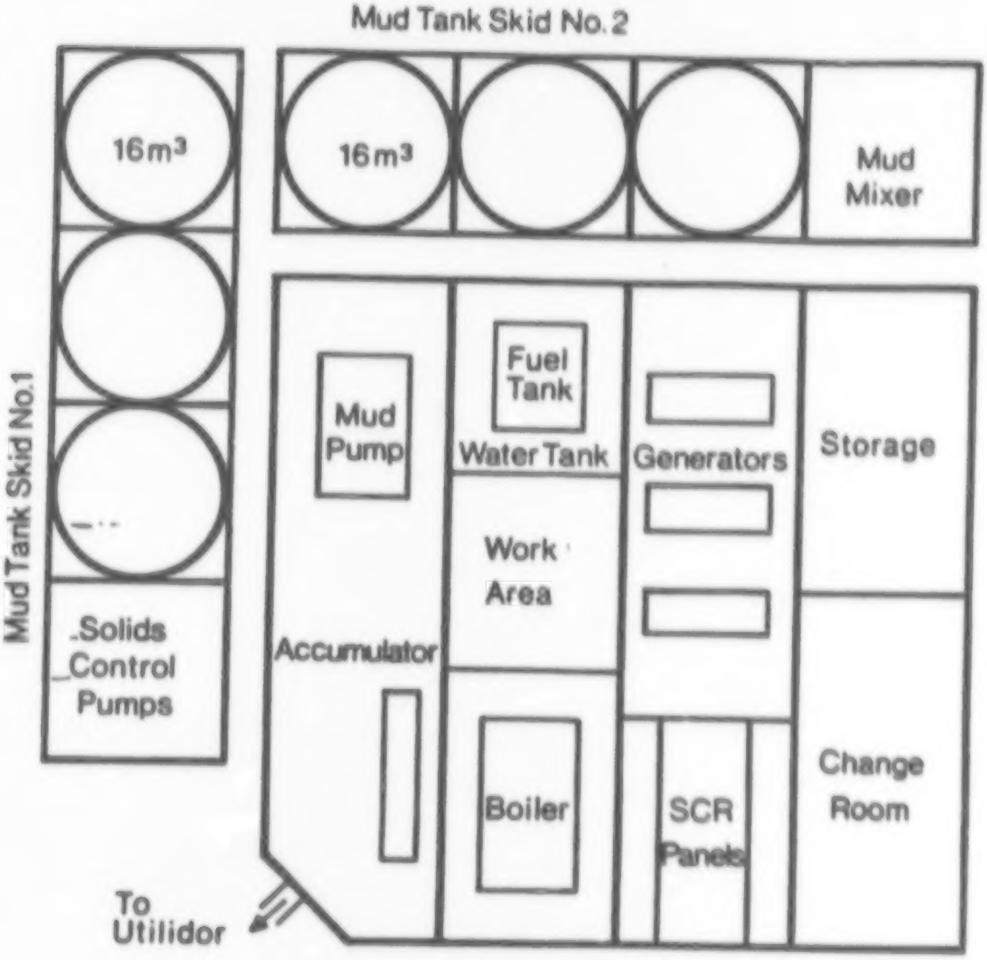

Transfer Line
Tilt Mast
Transfer Elevator
Travelling Block
Walkway
Racking Tower
Hydraulic Cylinder
Pipe Handling System
Draw Works
Wheel Assembly
Substructure
Wheel Assembly

FIG. A - 1

FIG. A-2

Central System



Mud Tank Skid No. 2
16m³
16m³
Mud Mixer
Mud Tank Skid No.1
Solids Control Pumps
Mud Pump
Fuel Tank
Water Tank
Generators
Storage
Work Area
Accumulator
Boiler
SCR Panels
Change Room
To Utilidor

Solids Control System

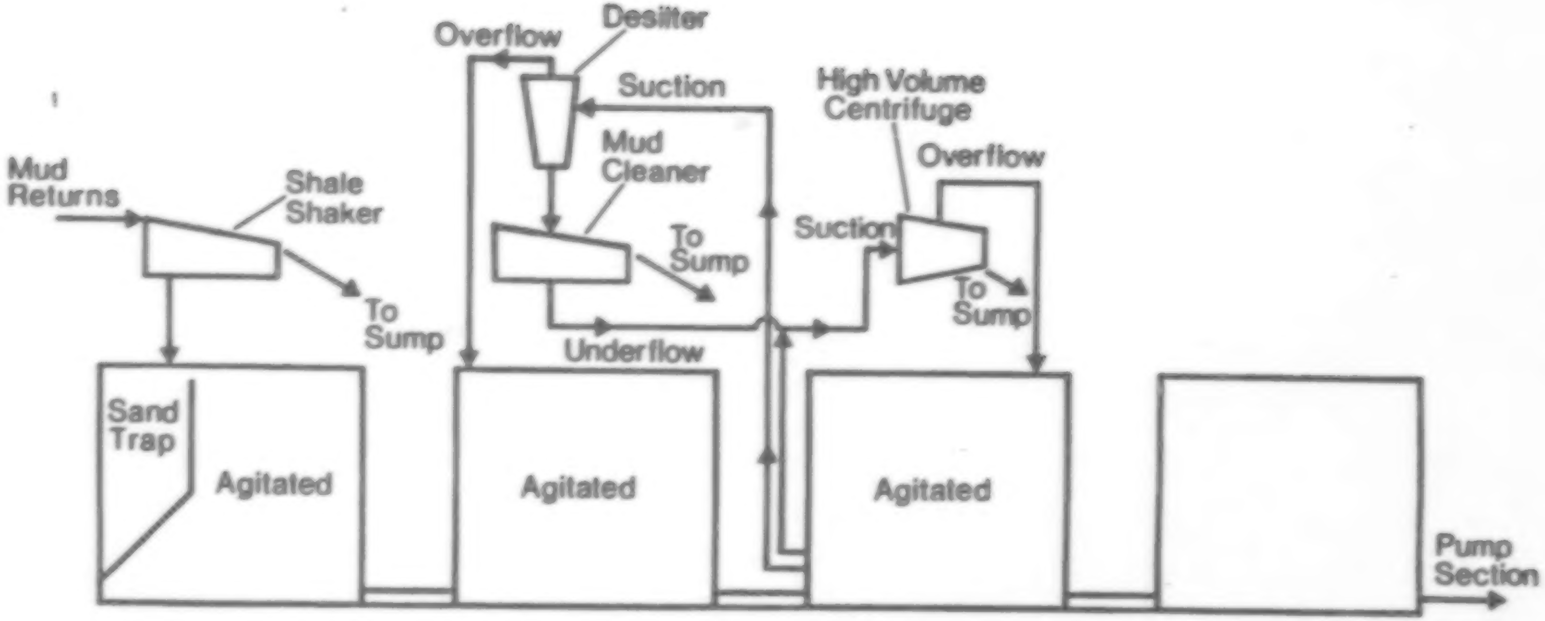
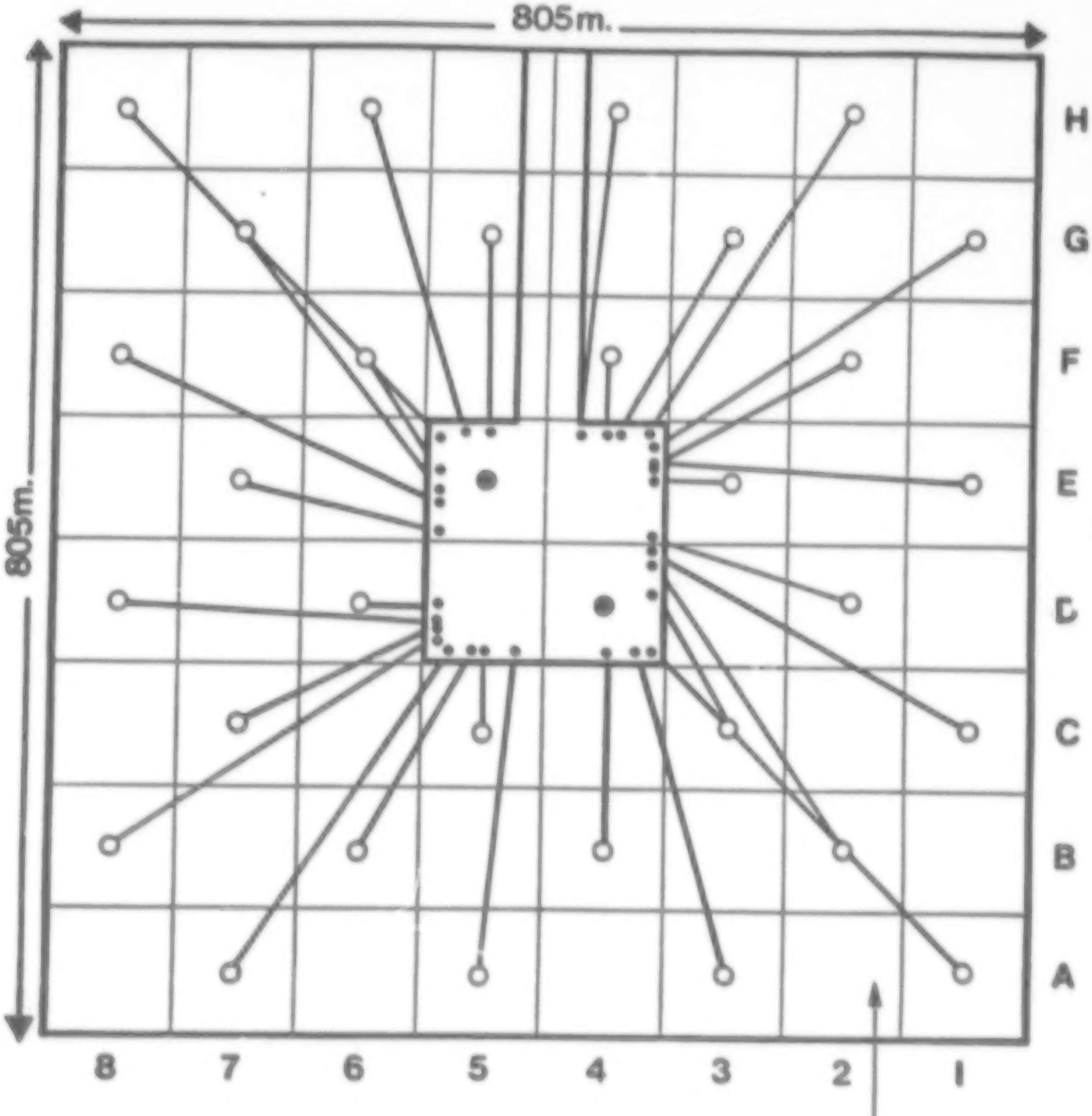

Overflow
Desilter
Suction
High Volume
Centrifuge
Mud
Cleaner
Overflow
Mud
Returns
Shale
Shaker
To
Sump
Suction
To
Sump
To
Sump
Underflow
Sand
Trap
Agitated
Agitated
Agitated
Pump
Section

FIG. A-3

FIG. B-2

Typical Pad and Well Layout

One Quarter Section (64 ha)



805m.
805m.
H
G
F
E
D
C
B
A
8
7
6
5
4
3
2
1

• Spud Location ○ Bottom Hole Location One Hectare

Cumulative Average of Days to Drill a Well

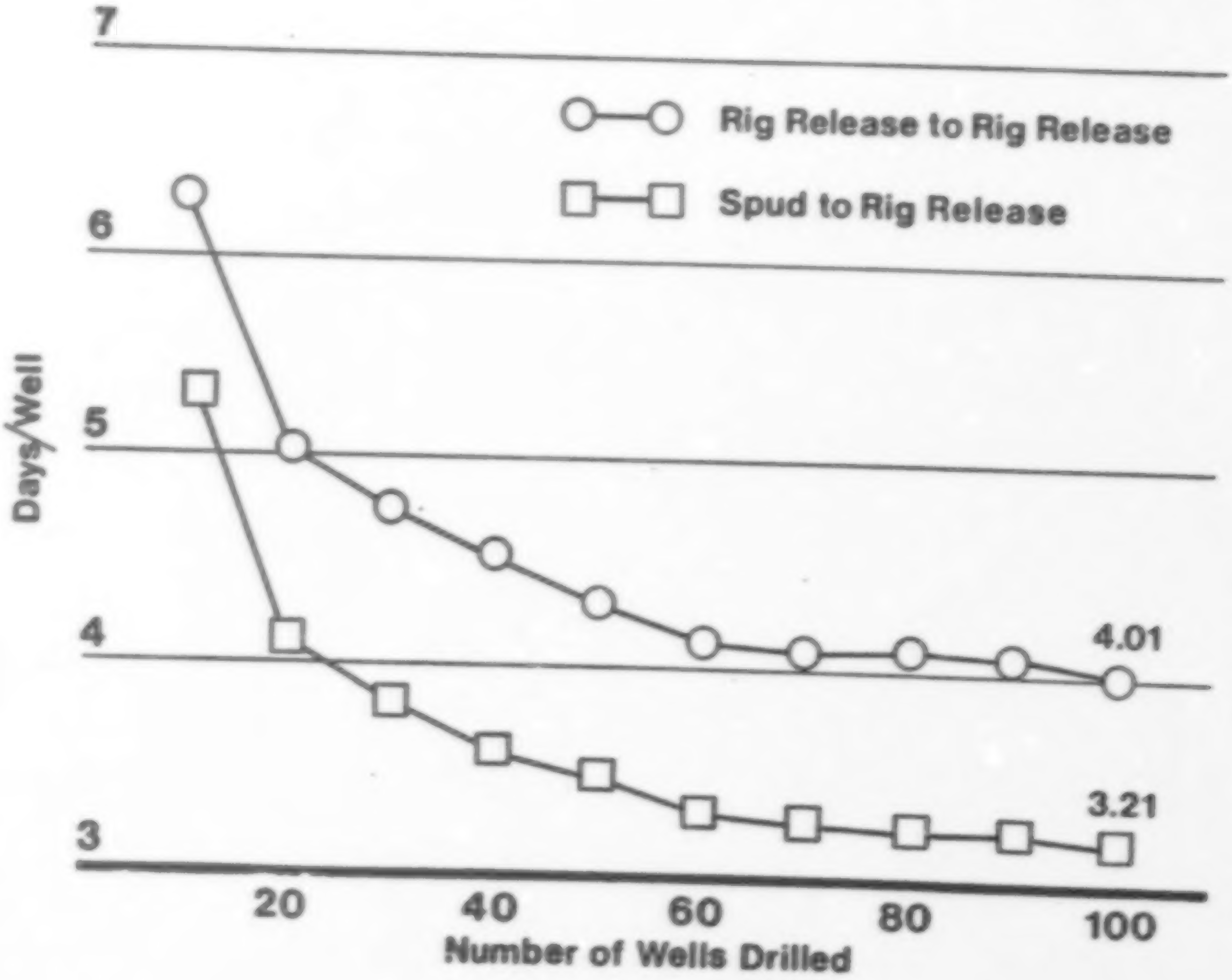
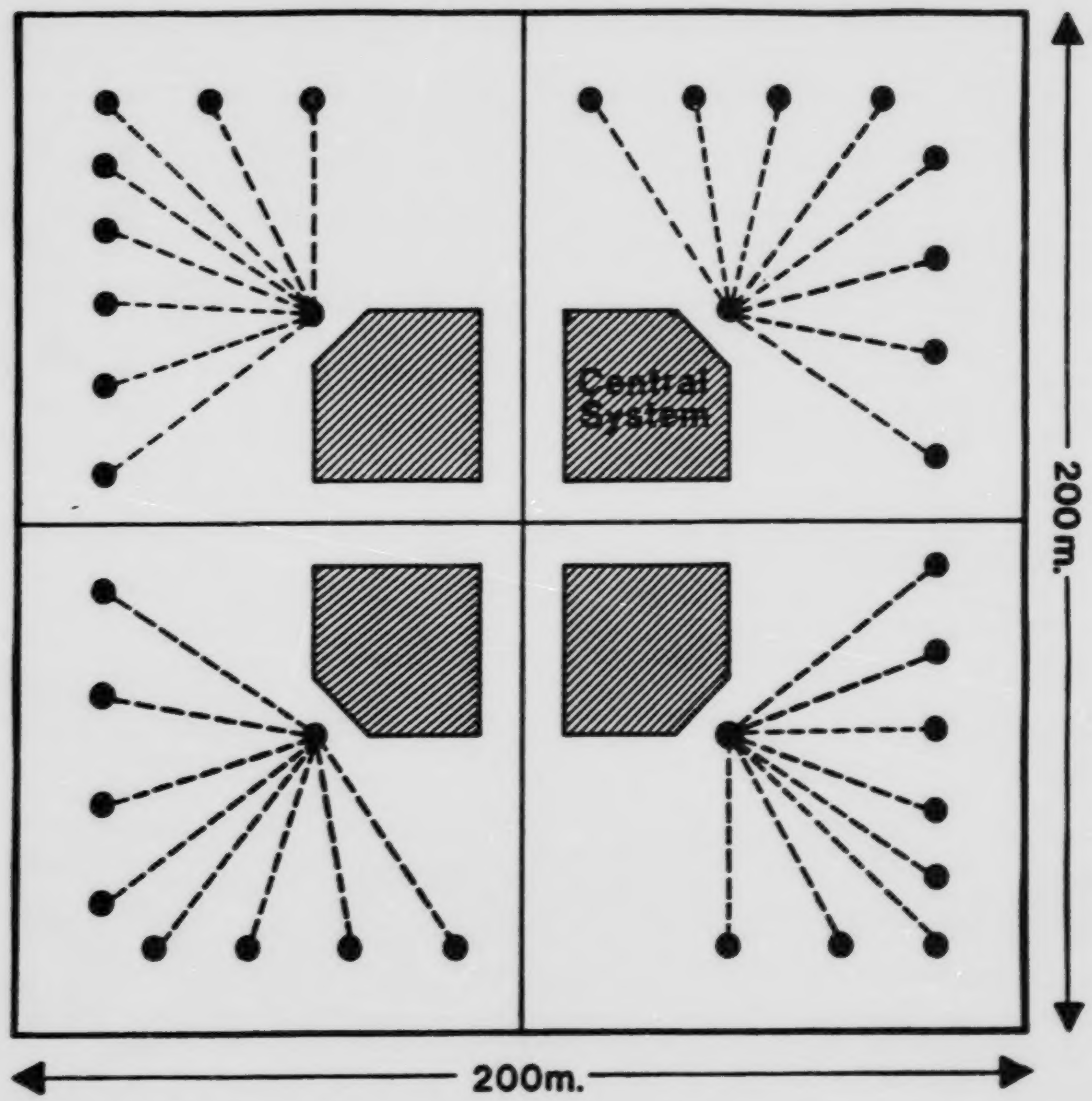


FIG. B-3

FIG. B-6

Central System Locations on a Drilling Pad


Central System
200 m.
200m.

Alberta OIL SANDS
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PETROLEUM SOCIETY OF CIM

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(22)

ESSO RESOURCES HORIZONTAL HOLE PROJECT AT COLD LAKE

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THIS PAPER IS TO BE PRESENTED AT THE 30TH ANNUAL TECHNICAL MEETING OF THE PETROLEUM SOCIETY OF CIM IN BANFF, MAY 8 — 11, 1979. DISCUSSION OF THIS PAPER IS INVITED. SUCH DISCUSSION MAY BE PRESENTED AT THE 30TH ANNUAL MEETING AND WILL BE CONSIDERED FOR PUBLICATION IN CIM JOURNALS IF FILED IN WRITING WITH THE TECHNICAL PROGRAM CHAIRMAN PRIOR TO THE CONCLUSION OF THE MEETING.

ABSTRACT

The Alberta Oil Sands comprise the bulk of Canada's petroleum reserves. The bitumen in these deposits is too viscous to flow naturally and cannot be produced by conventional oilfield techniques. Where the deposits are close to the surface, mining can be employed to recover the Oil Sands. In many areas, however, the over burden thickness is such that in-situ recovery techniques provide the only means of recovering bitumen.

This paper describes the drilling details of a well which will be used in an in-situ recovery pilot at Cold Lake. The well, Imp 78 Horizontal Leming Ex 9-6-65-3 was spudded conventionally and then deviated so that its final wellbore path was horizontal in the Clearwater formation. Over 1000' of pay section was contacted by this well in a zone which is only 160' thick. Details about the well planning, drilling equipment, drilling fluid, survey program, casing and problems encountered are discussed.

INTRODUCTION

The Alberta Oil Sands are one of the world's largest known reserves of petroleum. The main deposits, Athabasca, Cold Lake, Peace River and Wabasca contain about 900 x 10^9 barrels, 95% of the petroleum discovered to date in Canada.

The heavy oil in the sands is very viscous and cannot be recovered in its natural state by conventional production methods. The two commercial plants presently in operation surface mine the oil sands and upgrade the bitumen recovered into light oil.

The reserves in the Cold Lake deposit (Figure 1) cannot be recovered by mining techniques because 1000' of over burden overlies the oil bearing sands. Here, in-situ recovery methods provide the only means of extracting the heavy bitumen. There are many recovery pilots in operation in the area and most involve the application of external energy, such as steam, to reduce the viscosity of the heavy crude and allow production.

To introduce heat into the oil sands, vertical or moderately deviated wells are drilled into the oil bearing formation. Because the wells have limited drainage capabilities, the well spacing is closer than in conventional producing fields and large numbers of wells are required.

A well in which a large section of oil sand can be contacted may provide increases in both production rates and recovery levels. The only means by which such lengths of reservoir can be reached is with a highly deviated well which enters the reservoir at a near horizontal inclination.

Imp 78 Horizontal Leming Ex 9-6-65-3 is such a well. It was spudded conventionally on March 21, 1978 and then deviated so that its final wellbore path was horizontal, 1558' below the surface. This paper discusses the methods and techniques employed to drill this well.

PLANNING

(a) Pre-Program

Esso Resources (formerly Imperial) has operated pilot studies in the Cold Lake area since 1964. Over 100 evaluation wells and 190 pilot related wells have been drilled to date. The initial pilot wells were vertically drilled but more recent wells have been deviated up to 35^{O} from vertical.

Only minor drilling problems have been encountered at Cold Lake. The first 500' of over-burden is unconsolidated glacial drift. This formation enlarges somewhat as the well is drilled but is sufficiently competent to allow angle buildup. Marine shales underlie the drift zone. These shales are more competent than the upper drift zone and stay near gauge during the drilling operation. The oil sands underlying the shale section are a non-cemented mixture of rock fragments and clay minerals. This formation drills very quickly and hole stability is usually good.

Because all previous wells in the area were only moderately deviated, a comprehensive literature search of high angle drilling was undertaken before planning began. Wherever possible, operators, contractors and service companies having experience with this type of drilling were contracted before the well program was prepared. Thus, equipment and tools which had worked successfully in other areas were identified.

The initial objectives of the horizontal well project were:

- 1000' of pay zone was to be penetrated in the Clearwater Formation
- the hole was to be near the bottom of the Clearwater
- accurate knowledge of the bottom hole location was required
- the desired production casing size was 7-5/8"

(b) Drilling Program

In order to accomplish the objectives, the following drilling program was prepared. As will be discussed later, not all these steps were actually followed:

1. Pre-set the conductor pipe.
2. Drill a 12-1/4" hole to kick-off depth of 150'.
3. Run a 7-3/4" Dyna-Drill with a 12-1/4" bit to 630' T.V.D., building angle at 4-1/4°/100'.
4. Run a multishot magnetic survey.
5. Ream the 12-1/4" hole to 17-1/4".
6. Underream the 17-1/4" hole to 21".
7. Run 16" surface casing and cement to surface.
8. Head up and displace casing to oil-mud.
9. Drill out the float and shoe with a 14-3/4" bit.
10. Run in with an 8-3/4" bit and build angle at 4-1/4°/100' to the Clearwater (approximately 1451' T.V.D.).
11. Run a multishot survey.
12. Ream the 8-3/4" hole to 9-1/2".
13. Ream the 9-1/2" hole to 14-3/4".
14. Run 10-3/4" casing to the shale above the Clearwater (approximately 1441' T.V.D.) and cement to surface.
15. Run a gyro survey.
16. Drill out with a 9-1/2" bit and make 5' of hole below casing shoe.
17. Drill with a 7-7/8" bit and build angle at 4-1/4°/100' to 1460' T.V.D.
18. Build angle at 1°/100' to 1561' T.V.D.
19. Run a multishot survey.
20. Ream the 7-7/8" hole to 9-1/2".
21. Run a 7-5/8" slotted liner.
22. Install the wellhead and release the rig.

A number of operational considerations influenced the procedures which were included in the above program:

- The kick-off depth was to be as shallow as possible in order to minimize the rate of angle build up.
- A comprehensive directional survey program was needed to ensure the directional objectives were met.
- The optimum hole size for directional drilling was 7-7/8" - 8-1/2", thus requiring a pilot hole, later reamed to a larger size.
- Underreaming the surface hole was necessary because the rig used has a 17-1/2" rotary table. A 21" hole was required to run the 16" surface casing.

In order to increase the chances of successfully completing this program, a spare 5-1/2" slotted liner was prepared. If hole stability was such that the drilling in the horizontal section could not be continued, then the 7-5/8" liner would be run. Drilling would continue below the 7-5/8" liner and the smaller liner would be run to bottom. Similarily, if the 7-5/8" liner became stuck during the running operation, it would be possible to drill out the end of the liner, clean out the hole, and run the 5-1/2" liner to bottom.

(c) Organization

Personnel for this operation were selected so that decision making could be concentrated at the rig site. Two drilling supervisors and a drilling engineer were on location at all times along with experienced service company personnel. Because of the large number of people on the lease, an organization chart (Figure 2) was prepared to identify responsibilities and communication paths. A chart, outlining when certain variables, such as angle build-up rate and hole drag were becoming critical, was also prepared. This alerted personnel to potential problems and ensured that remedial procedures could be undertaken without delay.

OPERATING DATA

(a) Wellbore Path

Forty-two days after spud, well 9-6 was successfully completed. The final angle at the bottom of the hole was 90.2° from vertical (Figure 3). The well was horizontally displaced 2045', while the total vertical depth reached was 1558' K.B. In order to accomplish this, it was necessary to drill 2955' of hole.

The main program objective was obtained - 1059' of pay penetrated in the Clearwater formation, a zone which is 160' thick.

(b) Time Analysis

Because of the numerous steps involved in the program, the total time required to drill was longer than would be expected for a normal 3000' well. The progress in depth vs. the days from spud is shown in Figure 4. The time required to complete various operations is listed in Table I.

TABLE I

TIME ANALYSIS

OPERATION	TIME (DAYS)	% OF TOTAL
Drilling	2.9	6.9
Ream Hole to Larger Size	5.3	12.6
Surveys	3.8	9.0
Tripping	2.9	6.9
Run Casing	3.6	8.3
W.O.C., Head-Up, Drill Out	4.3	10.2
Ream to Bottom	3.1	7.4
Miscellaneous Operations and Problems	16.2	38.6

(c) Drilling Rig

The rig selected for well 9-6 is rated to drill to 7500'. A rig this size was used for the following reasons:

- Sufficient pump capacity was required to clean hole sizes up to 21" in diameter.
- Sufficient hoisting capacity was required in the event of severe drag.
- The mud system had to accommodate additional solids control equipment.
- The table had to be sufficiently large to run 16" casing.
- The capability of pulling triples simplified handling of some bottom assemblies.

The rig specifications are listed in Table II.

TABLE II

ESSO RIG 2E SPECIFICATIONS

Drawworks	- 600 h.p.
Mud Pump	- 560 h.p.
Table Size	- 17-1/2"
Mud Tank Volume	- 400 bbls
Mud Solids equipment	- Shale Shaker, Desilter, Centrifuge

(d) Downhole Tools

Two general types of downhole assemblies were used in drilling the well, an angle building assembly and a hole opening assembly. All components were conventional pieces of equipment, locally available.

(i) Angle Building Assembly

Figure 5 shows the angle building assembly. This basic assembly, although varied slightly in different portions of the well, was used to pilot the surface and intermediate hole and to drill the production hole. On the bottom was a mill tooth bit rotated by a Dyna-Drill. This downhole hydraulic motor is powered by pumping mud down the drill pipe. A 6-1/2" Dyna-Drill was used in both the 12-1/4" and the 9-1/2" pilot holes.

Angle building was accomplished using either a bent sub or a bent housing Dyna-Drill. The selection of the proper kick sub was determined by the directional driller according to his progress relative to the angle building target. The three subs used, 1.5°, 2°, and 2.5° provided varying angle build-ups as shown in Figure 6.

Non-magnetic drill collars were run above the Dyna-Drill. Three non-magnetic collars were run to the 10-3/4" casing point and four were run from there to bottom. In highly deviated holes the magnetic interference of drill pipe on the directional survey compass is more pronounced than in vertical holes. The number of collars that were run, adequately removed any interference and allowed high quality surveys.

Heavy weight drill pipe was run immediately behind the monel collars. This pipe provided some weight on bit, but its main purpose was to place the steel drill collars further uphole as the wellbore approached the horizontal. This unconventional arrangement had two advantages, the heavy drill collars were placed in a more vertical section of the hole, providing weight on the bit more effectively, and secondly, the chances of differentially sticking the drill string were minimized because of the reduced diameter of the heavy weight pipe in the highly deviated hole section.

(ii) Hole Opening Assembly

While opening the hole, the drill string was rotated conventionally and the reamer (Figure 7) effectively followed the pilot hole. The ported bullnose allowed circulation into the pilot hole, the non-rotating stabilizer was short and would not bury itself in the side of the hole. Because this stabilization was full gauge, it prevented excessive assembly vibration.

(e) Directional Survey

Directional surveys played a critical role in the success of this project. The hole had to be drilled in a particular direction, but in addition, it was imperative that the bottom hole location be known extremely accurately. Therefore, a comprehensive survey program was carried out.

(i) Equipment

The steering tool was used at all times in the pilot holes. This tool consists of a downhole directional sensing package which si in the non-magnetic drill collars. It is connected by wireline to surface providing constant surface readout of hole direction, thus indicating when direction is unsatisfactory. This allows immediate corrective action to be taken if necessary, which is particularly important in the high angle portion of the well.

Single shot magnetic surveys were run every 60' to provide a permanent survey record as the hole progressed.

A magnetic multishot survey was run at each casing point to provide a continuous survey record.

A gyroscopic survey was run inside the 10-3/4" intermediate casing to provide non-magnetic confirmation of the multishot surveys.

(ii) Computation

In addition to accurate data, a quick and reliable computation method was necessary. A telephone link from the drilling location to an IBM 370 computer in Edmonton was available and continuous computation of hole trajectory wa maintained.

(iii) Results

In the final analysis the survey record which best represented the wellbore path was the combination of the gyro survey to intermediate casing point meshed with the multishot magnetic survey from the intermediate casing to total depth.

However, if the directional requirements were less stringent, a reduced survey program would be sufficient to drill the well.

The continuous surface readout appears to be indispensible for operational purposes. Either the multishot or gyro survey appear to be satisfactory as a survey record.

(f) Drilling Fluid

The care with which drilling fluid is selected and maintained is a critical part of every drilling program. In high angle wells, the drilling fluid is even more critical since it must minimize torque and drag as well as clean the hole.

An oil-mud is a preferred fluid in such applications. This mud consists of a continuous oil phase, usually diesel oil, with water emulsified in the oil. Additives are used to stabilize the emulsion, oil wet mud solids and impart viscosity and fluid loss control to the mud.

Laboratory tests were run to determine the stability of heavy oil sand in the presence of both oil and water base mud. The tests simulated the shear rate which would exist at the wellbore face due to the circulating fluid. Although some hole enlargement was observed in both cases, hole stability with the oil-mud was superior.

A fresh water-gel mud was used to drill the surface hole. Fresh water sands close to surface prohibited the use of an oil-mud in this part of the well. Mud viscosity of 45 sec/qt was adequate to clean the hole during both the 12-1/4" Dyna-Drill run and the hole opening to 17-1/2" and 21".

Once the surface casing was installed, the fresh water based gel mud was displaced to the oil-mud. The initial mud weight was 8.0 ppg with a 5 lb/100 ft^2 yield point. Connections were tight throughout the piloting operation because of poor hole cleaning. This was due in part to the circulation rate which had to be maintained through the Dyna-Drill, which in turn limited the annular velocity. Conditions improved when the yield point was increased to 18 lb/100 ft^2. The mud properties at 1828' during pilot hole drilling, at 1937' after reaming the intermediate hole and in the horizontal section are shown in Table III. Overall, the muds used performed very well. No drilling problems were encountered and drag on trips was usually about 10,000 to 15,000 pounds in lower portions of the hole.

Solids control on the rig consisted of a shaker, 12 cone desilter and centrifuge. The shaker and desilter were used during surface hole and the centrifuge was used when the oil based mud was run. This equipment maintained drill solids below 5% by volume.

In order to minimize mud losses and spillage while using the oil-mud, extra equipment was installed on the rig as shown in Figure 8.

TABLE III

OIL-MUD PROPERTIES

	DEPTH 1828' (PILOT HOLE)	DEPTH 1937' (REAMED HOLE)	DEPTH 2830' (DYNA-DRILLED HOLE)
Mud Weight	8.1 ppg	8.5	8.1
Viscosity	65 sec/qt	70	61
PV	23 cp	28	26
YP	19 lb/100 ft^2	28 cp	18
Gel Strength	7/8 lb/100 ft^2	12/19	7/8
Solids	3%	6	4
Oil	76%	74	75
Water	21%	19	21

(g) Drag And Weight On Bit

As the hole inclination approached higher angles, the frictional drag on the drill string increased and satisfactory weight on bit became more difficult to maintain.

Figure 9 shows the situation at total depth. The different sections of the drill string are plotted against the factors which influence hook load, i.e., depth, inclination angle, and component weight.

The effective weight component is the weight of the section of the drill string multiplied by the cosine of the average inclination angle for that section; this component of drill string weight provides weight on bit.

The normal weight component is the weight of the section multiplied by the sine of the average inclination angle; this component of the drill string weight creates drag.

At the depth shown in Figure 9, all available weight on bit had been used up and it would have been necessary to add more drill collars uphole in order to continue drilling. This fact makes possible the computation of an average friction co-efficient for the hole.

By dividing the total effective weight on bit by the summation of all normal force components, the friction co-efficient is calculated to be .54. It should be noted that this co-efficient is actually a composite of classical drag, plus a ploughing force on the pipe connections in the open hole. Also, it was achieved with oil based mud in the hole; no doubt it would have been much higher if a water based drilling fluid had been used.

(h) Casing and Cementing

The casing strings run in the well consisted of the conductor pipe, surface casing, intermediate casing and production liner as shown in Figure 3.

The conductor pipe was 24" in diameter and was set before the drilling rig moved onto the lease.

The surface casing string was run through the glacial drift and set at 549' measured depth. The hole angle at this point was 19.5° but no problems were encountered in running the casing. The 16" casing had a yield strength of 55,000 psi and was cemented to surface with Class "G" Oilwell cement.

The 10-3/4" intermediate casing string was set at the top of the Clearwater Formation. Although the hole angle at the bottom of the string reached 70.1°, there were no problems in running the casing to bottom through the oil-mud.

The intermediate string was designed to withstand the elevated temperatures common in wells undergoing thermal stimulation combined with stress due to a deviated wellbore. Stress in constrained casing builds up as temperature is increased in accordance with equation (1).

Equation .... (1)

$$\sigma_c = \alpha E (\Delta T)$$

where σ_c = compressive stress, psi
α = co-efficient of thermal expansion, in./in.-°F
E = elastic modules, psi
ΔT = temperature change, °F

Over the temperature range of interest, equation (1) yields a compressive stress of about 200 psi/°F.

If steam is injected down a casing-tubing annulus, the internal pressure, in conjunction with the compressive stress due to heating, creates biaxial stress. The effect of combining these stresses can be analyzed using Mises yield criteria.

In addition to the thermal related stress, bending the casing in a deviated wellbore creates tensile stress on the outside of the bend and compressive stress on the inside of the bend. The stress due to bending is given by equation (2).

Equation .... (2)

$$\sigma_b = \pm 218 (\theta) (D)$$

where σ_b = bending stress, psi
θ = rate of change of angle, °/100'
D = outside diameter, in.

For 10-3/4" casing in a wellbore deviated 5°/100', the stress due to bending is 11,700 psi at the outer fibers.

In order to operate under these conditions, casing with buttress joints and a yield strength of 95,000 psi was used. It was designed to undergo limited plastic deformation if necessary in accordance with a procedure outlined by Holliday[1].

The intermediate string was cemented to surface with Oilwell cement + 30% silica flour. This cement mixture retains its strength under high temperature conditions.

As an added precaution, the intermediate string was made up using tongs which measured both the torque and turns applied to the casing, thus allowing identification of proper or improper joint make-up.

The last string run was the 7-5/8" liner. It was run to bottom and tied back to the intermediate casing string. This liner was not cemented in place and perforated. Instead, 800' of the liner was slotted, allowing bitumen production, yet minimizing the amount of sand which could enter the wellbore.

In order to reduce friction and drag while running the liner, a Hydril Super "EU" connection was selected. This joint has a tapered shoulder on the coupling in comparison to a square shouldered API connection. No centralizers were used on the liner.

The shoe on the liner was brass and could be drilled out if necessary. Thus, the hole could have been conditioned and the spare 5-1/2" liner could have been run if the larger liner became stuck during the running operation. A 2-7/8" stinger was tied into the shoe so that fluid could be circulated to the end of the liner if fill was encountered.

The 7-5/8" liner went to bottom without problem. It was not necessary to circulate through the stinger as no fill was encountered.

(i) Problems

A number of problems were encountered in the surface hole. The corrective action proved successfull in each case and after surface casing was set, progress was relatively trouble free.

The most troublesome problem occurred in enlarging the 12-1/4" pilot surface hole. The original plan called for a 30' long bullnose to guide the hole opener in the pilot hole. This tended to bury itself in the soft formation and start drilling a new hole. The surface pilot hole was drilled three times before it was discovered that a short non-rotating stabilizer ahead of the hole opener was best able to follow the pilot hole. Although 7 days had been planned to drill surface hole, run casing and head up, it took 14 days. This assembly was used again in opening the intermediate hole and it performed very well.

Initially the wireline connecting the steering tool to surface proved troublesome. The line continually frayed at the rope socket on the downhole instrument requiring repairs or fishing. It was determined that vibration was causing the damage. A latching device for the downhole instrument was installed and tension was held on the wireline while drilling. The problem disappeared for the remainder of the hole.

At surface casing point a multishot survey was planned. The Dyna-Drill was pulled and a slick string was run in. Severe bridging was encountered on the trip and finally the Dyna-Drill and bent sub were run and the multishot survey taken with these tools in the hole. Succeeding multishot surveys were run in the same manner without problem.

More interesting than the problems encountered are those that had been anticipated but which proved to be minor.

One question was whether weight on bit could be maintained against frictional forces in the horizontal section of the hole. The heavy weight pipe and drill collars uphole, combined with the low co-efficient of friction provided by the oil base mud allowed sufficient bit weight to be maintained. In fact, more horizontal hole could have been drilled if it had been required.

A second question was whether the angle build up rate of 4-1/4°/100' could be maintained. The surface hole was piloted with 12-1/4" bits and inclination angle was built successfully. The intermediate pilot hole size was planned to be 8-3/4" to provide a good chance for angle build up, but the program was changed after our success with 12-1/4" pilot hole. Pilot hole of 9-1/2" was drilled (normally more difficult) and no serious problems were encountered. This made it possible to open the hole from 9-1/2" to 14-3/4" in one step compared to the two step procedure in the drilling program.

A very serious concern was whether the large casing, particularly the 10-3/4", would go down the crooked hole and contingency designs were prepared at great expense. All casing strings went in very smoothly.

(j) Cost

The drilling cost of the horizontal well was about 8 times the cost of a typical producing well. The pay section contacted was about 7 times greater than that reached by a typical well.

To some extent, the cost of this well was inflated by the experimental nature of the project and by the contingencies built into the program. Significant savings could be realized in future wells if casing sizes were reduced to 13-3/8", 9-5/8", and 5-1/2". It would also be possible in future wells to drill more than 1000' of near horizontal hole and the incremental cost of this drilling would be reasonable since much of the investment is in the uphole portion of the well.

SUMMARY

The successful completion of Leming Ex 9-6-65-3 broadens the horizons of the drilling industry. To our knowledge, it is the only well of this nature drilled by the petroleum industry in the Western world. The well was drilled using conventional technology and, in most cases, local services. The credit for drilling this well lies not only with the engineering and supervisory personnel involved with the project, but also with the high calibre of personnel and equipment supplied by the respective service companies. Although designed for the heavy oil sands, a horizontal well may have applications in conventional reservoirs. A well having a long horizontal path in a producing zone could improve reservoir recovery as well as the economics of infill drilling. In addition, fields inaccessible because of surface constraints can now be tapped. Thus, more wells of this type may well be drilled in the future.

ACKNOWLEDGEMENTS

The Authors wish to express their appreciation to Esso Resources Canada Limited for permission to prepare and present this paper. They wish also to acknowledge the assistance provided by co-workers, especially, C.C. Bombardieri, I.M. Parker, D.R. Aberdeen, and J.A. McNutt. Valued assistance was also provided by industry personnel, among those being B. Shaw, H.W. Fichtner, I. McLellan, G. Pollard, and G. Edwards.

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8. McLellan, I., Well Summary, Imp 78 Horiz Leming 9-6-65-3 W4, Unpublished Baroid Report August 1978
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COLD LAKE - OIL SANDS DEPOSITS

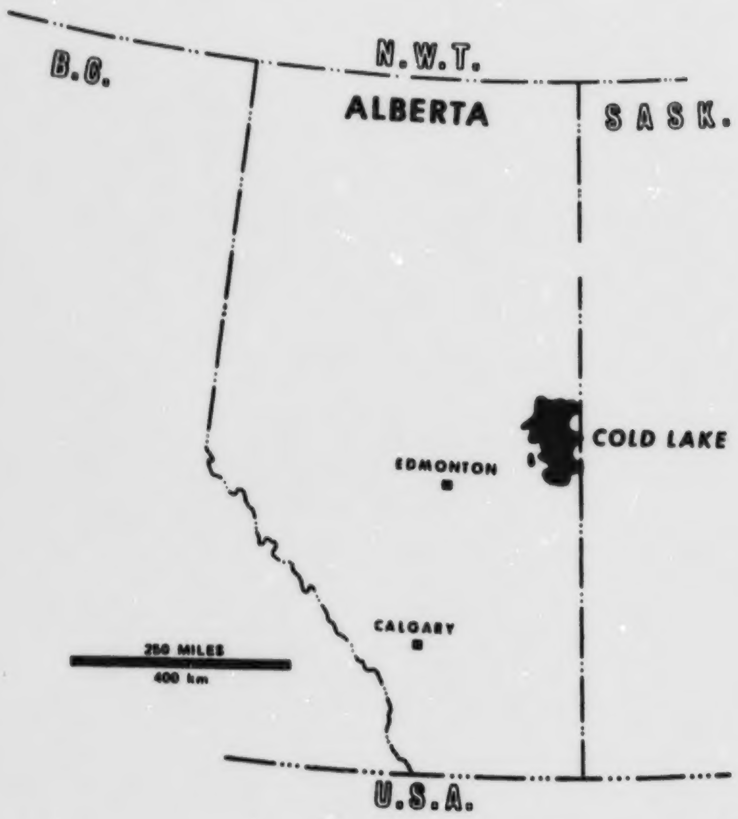

B.C.
N.W.T.
ALBERTA
SASK.
COLD LAKE
EDMONTON
CALGARY
250 MILES
400 km
U.S.A.

FIGURE 1

COLD LAKE
HORIZONTAL WELL ORGANIZATION CHART

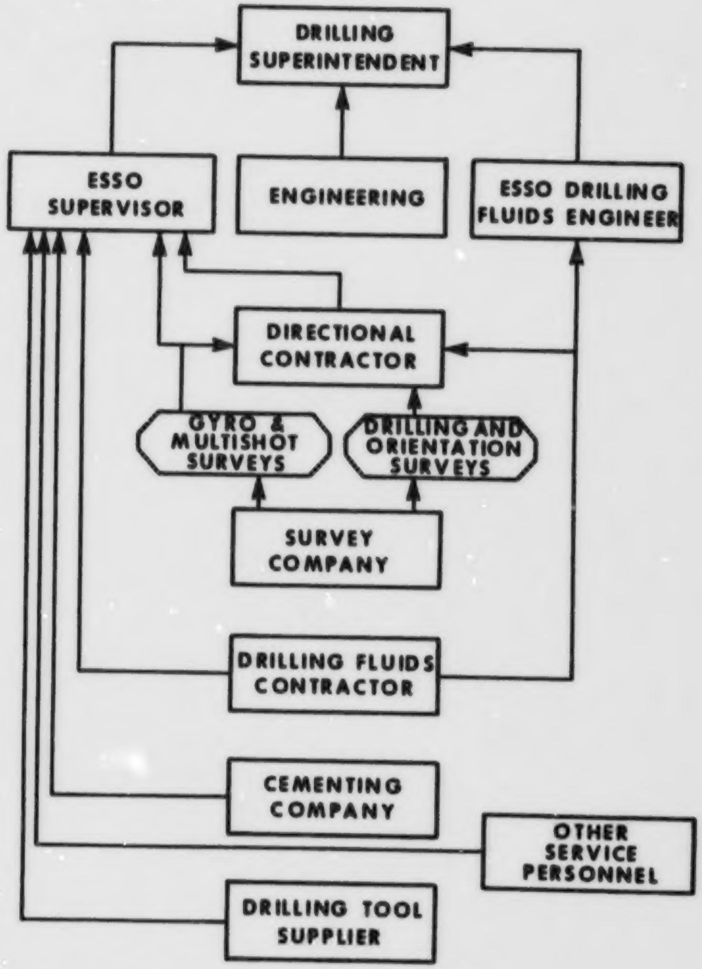

DRILLING SUPERINTENDENT
ESSO SUPERVISOR
ENGINEERING
ESSO DRILLING FLUIDS ENGINEER
DIRECTIONAL CONTRACTOR
GYRO & MULTISHOT SURVEYS
DRILLING AND ORIENTATION SURVEYS
SURVEY COMPANY
DRILLING FLUIDS CONTRACTOR
CEMENTING COMPANY
OTHER SERVICE PERSONNEL
DRILLING TOOL SUPPLIER

FIGURE 2

WELL SCHEMATIC - ACTUAL

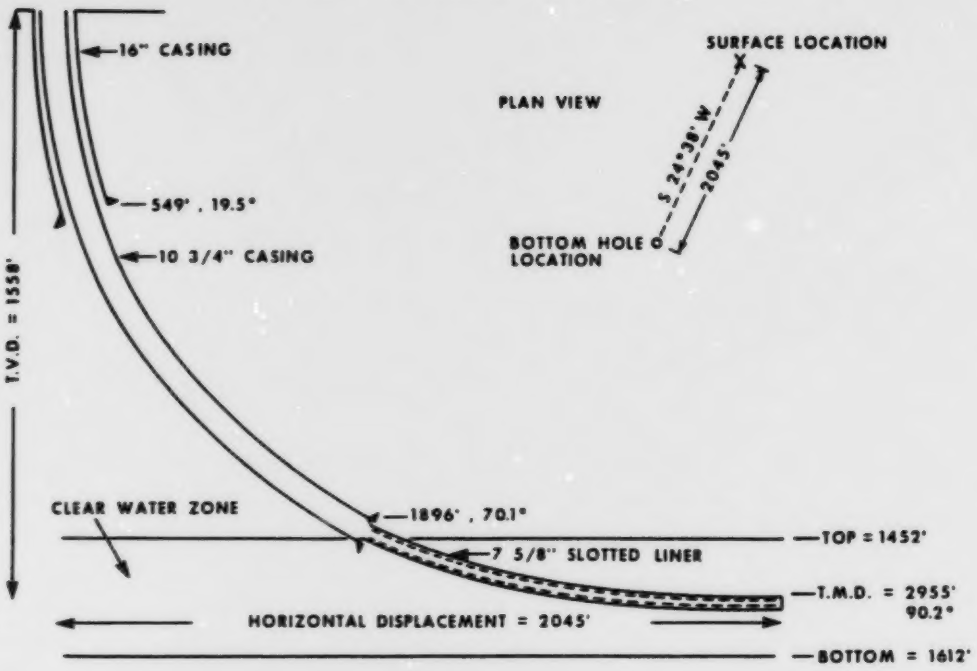

16" CASING
SURFACE LOCATION
PLAN VIEW
S 24°38' W
2045'
549', 19.5°
BOTTOM HOLE LOCATION
10 3/4" CASING
T.V.D. = 1558'
CLEAR WATER ZONE
1896', 70.1°
TOP = 1452'
7 5/8" SLOTTED LINER
T.M.D. = 2955' 90.2°
HORIZONTAL DISPLACEMENT = 2045'
BOTTOM = 1612'

FIGURE 3

DEPTH VS DAYS

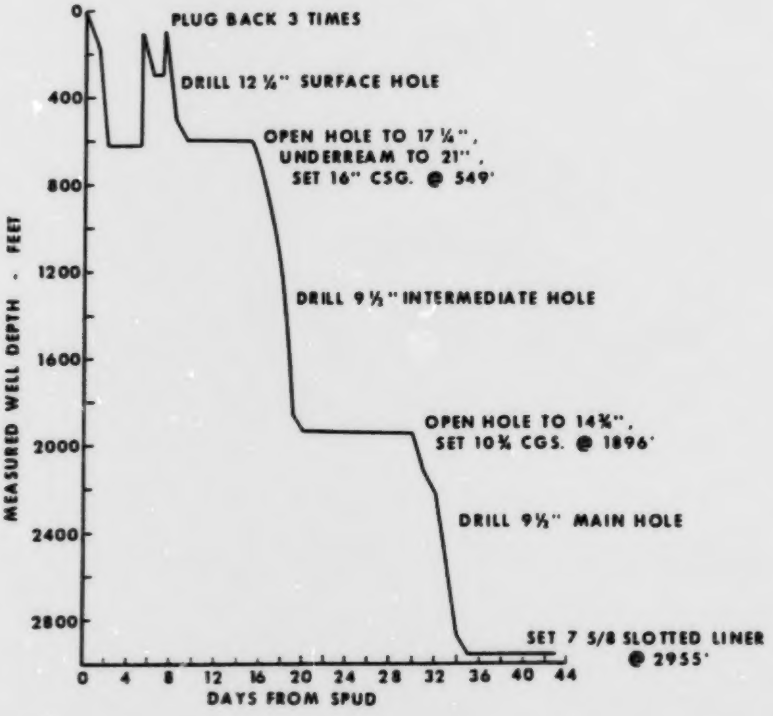


FIGURE 4

ANGLE BUILDING ASSEMBLY

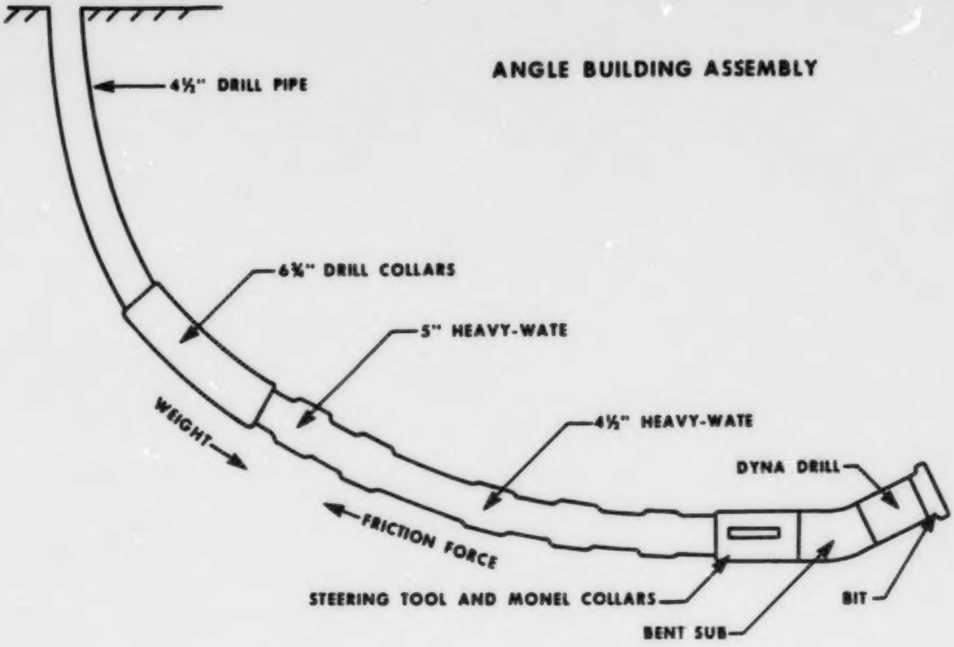

4½" DRILL PIPE
6¾" DRILL COLLARS
5" HEAVY-WATE
4½" HEAVY-WATE
WEIGHT
FRICTION FORCE
DYNA DRILL
STEERING TOOL AND MONEL COLLARS
BENT SUB
BIT

FIGURE 5

DOG - LEG SEVERITY AND BENT SUB VS. DEPTH

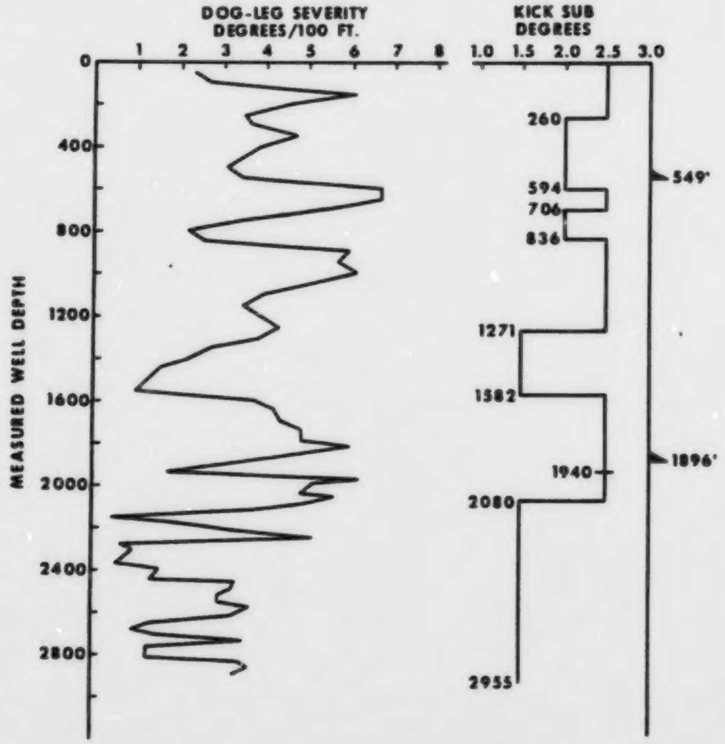


FIGURE 6

HOLE OPENING ASSEMBLY

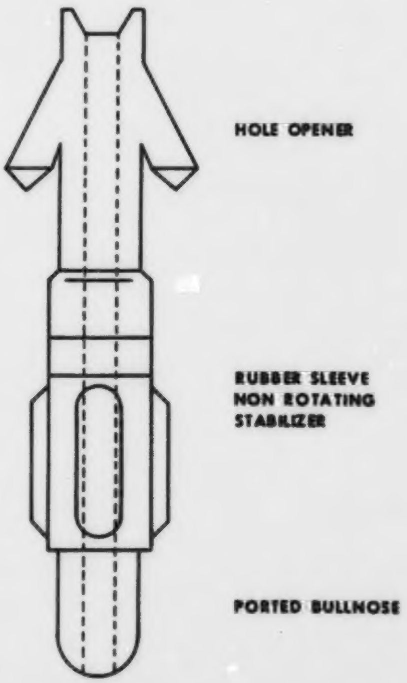

HOLE OPENER
RUBBER SLEEVE NON ROTATING STABILIZER
PORTED BULLNOSE

FIGURE 7

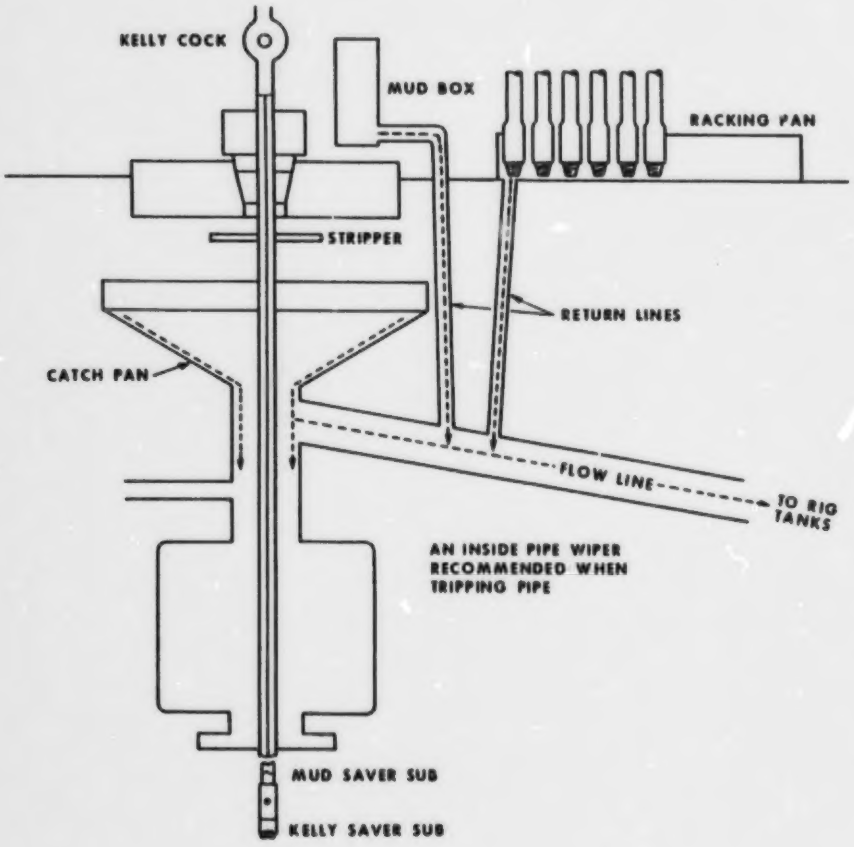
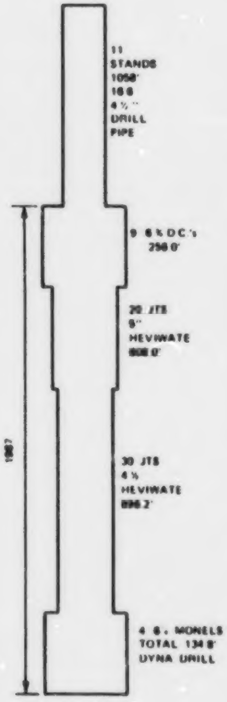

KELLY COCK
MUD BOX
RACKING PAN
STRIPPER
RETURN LINES
CATCH PAN
FLOW LINE
TO RIG TANKS
AN INSIDE PIPE WIPER RECOMMENDED WHEN TRIPPING PIPE
MUD SAVER SUB
KELLY SAVER SUB

FIGURE 8

CALCULATION OF HOLE DRAG OFF BOTTOM AT TD.


11 STANDS 1050' 18.8 4 ½" DRILL PIPE
9 6 ¾ DC's 256.0'
20 JTS 5" HEVIWATE 608.0'
30 JTS 4 ½ HEVIWATE 896.2'
4 6. MONELS TOTAL 134.8' DYNA DRILL
1987

MEASURED DEPTH IN FEET	TRUE VERTICAL DEPTH	INCLINATION ANGLE	WT/FT	AIR WT	EFFECTIVE WEIGHT COMP EW	NORMAL WEIGHT COMP NW
0	0	0				
			18	19,044	17,057	7,134
1050.3	988	44°				
			101	25,856	16,161	19,514
1316.5	1135	54°				
			49	29,702	13,641	26,496
1823.9	1426	71.5°				
			41	36,744	6,296	16,202
2820.1	1548	88.8°				
			83	11,188	97	11,188
2955	1556	90.2°				
				TOTAL	54,644	100,524

AT THIS POINT ESSENTIALLY ALL THE AVAILABLE WT HAD BEEN USED TO GET TO FINAL TOTAL DEPTH

$\mu \quad \frac{54,644}{100,538} \quad .54$

FIGURE 9

009276

Alberta OIL SAND
NFORMATION CENTRE

DRILLING HIGH ANGLE DIRECTIONAL WELLS

Doug D. Baldwin, Ron W. Royal and Harmohan S. Gill, *Esso Resources Canada Limited,*
237 4th Avenue S.W., Calgary, Alberta, Canada.

㉓

Abstract. This paper describes Esso Resources Canada Limited's past experience and future plans for drilling high angle directional wells. Esso pioneered horizontal oil well drilling in Canada at Cold Lake, Alberta, and at Norman Wells, Northwest Territories. A horizontal well will be highlighted where a closure of 1407 m was accomplished at a vertical depth of 489 m. The significant technical challenges of horizontal oil well drilling in shallow formations encompass the need to rapidly build angle, reduce torque and drag, apply weight on bit, maintain directional control and recognize the limitations of well evaluation. The paper summarizes problems of drilling horizontal wells and high angle wells at high latitudes. Esso's plans to directionally drill approximately 154 wells primarily from six man-made islands in the Mackenzie River at Norman Wells are discussed. Drilling performance for initial wells drilled in the Norman Wells Expansion Project will be presented.

Résumé. Cette communication traite de l'expérience passée et des plans futures d'Esso Resources Canada Limited dans le domaine du forage de puits fortement déviés. Esso a inauguré le procédé de forage de puits pétroliers horizontaux au Canada à Cold Lake dans l'Alberta et à Norman Wells dans les territoires du Nord–Ouest. On donne l'exemple d'un puits horizontal d'une longueur de 1407 m réalisé à partir d'une profondeur de 489 m. Le forage horizontal dans des formations peu profondes pose d'importants défis techniques, et en particulier la nécessité d'augmenter rapidement l'angle de déviation, de réduire le couple et la résistance, d'exercer plus de pression sur l'outil de forage, de maintenir le contrôle de la déviation et de reconnaître les limites dans l'évaluation des puits. La communication passe en revue les problèmes qu'entraîne le forage de puits horizontaux et hautement déviés dans les régions nordiques. Elle étudie les plans d'Esso prévoyant de forer quelque 154 puits fortement déviés surtout à partir de six îles artificielles construites dans le fleuve Mackenzie à Norman Wells. Elle donne également les résultats des premiers forages effectués dans le cadre du projet d'expansion de Norman Wells.

1. INTRODUCTION

Esso Resources Canada Limited has used directional drilling technology extensively in its development drilling programmes. Two wells drilled by Esso at Cold Lake, Alberta, and Norman Wells, Northwest Territories (Fig. 1) were the first wells drilled in the western world that had a substantial length of horizontal wellbore.

The Cold Lake horizontal well was spudded on March 21, 1978. The well was horizontally displaced 623.5 m at a true vertical depth (TVD) of 475 m. The principal reason for drilling this well was to field test the performance of a new heavy oil recovery technique developed by Esso named the Gravity Drainage Recovery Process.

Norman Wells J-29X was drilled in 1979 to evaluate the feasibility of using horizontal wells to develop the field since plans called for a closure approximately twice as large as that at Cold Lake for about the same TVD. Horizontal wells were considered since 75% of the reservoir lies under the Mackenzie River.

Drilling practices used in these two horizontal wells and plans for development drilling are discussed. Also discussed are critical design and operational practices including drill string design, drilling fluid selection, directional surveying techniques, logging and cementing.

Esso has embarked on an expansion project at Norman Wells where approximately 154 wells will be drilled in three years. Development plans and drilling performance to date is discussed.

2. COLD LAKE PAD DRILLING

Cold Lake is a heavy oil field in central Alberta which contains an estimated 25.3×10^9 m^3 of crude bitumen in place. Since the bitumen is too deep to be mined (450 m) it must be recovered by *in-situ* methods.

Esso has drilled pilot project wells in the Cold Lake area for steam stimulation since 1962. During the past 20 years, over 450 wells have been drilled. Prior to 1973, wells were drilled vertically from individual leases, including wells for the two initial steam stimulation pilot projects. In 1973, the concept of pad drilling was introduced during development of a third pilot project named Leming. The objective was to

11th World Petroleum Congress, London, England, August 28th - September 2nd, 1983

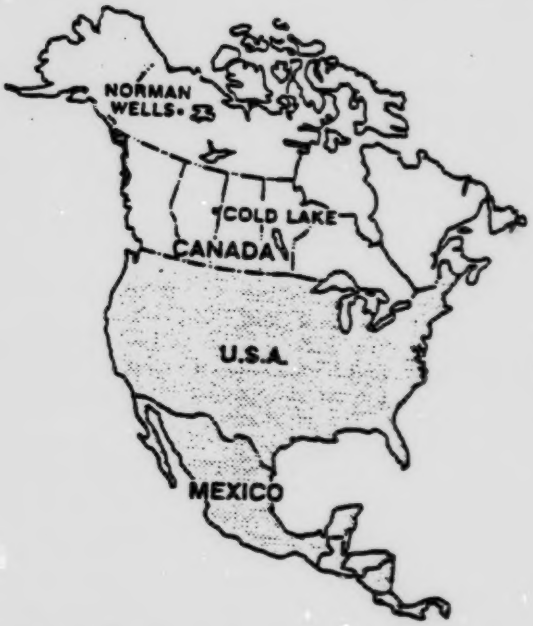

NORMAN WELLS
COLD LAKE
CANADA
U.S.A.
MEXICO

Fig. 1. Esso Resources Canada Limited, horizontal well locations.

improve efficiency of the production gathering and steam distribution systems and to minimize the environmental impacts associated with lease preparation and surface facilities.

Since inception of pad drilling, 250 wells have been drilled from 21 pads utilizing several different bottom hole spacings (Fig. 2). More than 90% of these wells were drilled directionally. The ten original pads drilled between 1973 and 1975 consisted of directional wells with closures (horizontal displacements) of 210 m and drift angles of 30°. These wells were drilled without problems in an average of 2.9 days. Wells on two pads drilled in 1978–79 had closures of 120–245 m and drift angles up to 45°. Ninety wells drilled in 1980 from six new pads had closures reaching 307 m and drift angles as high as 67°. The pad configuration used for the most recent wells is shown in Fig. 3.

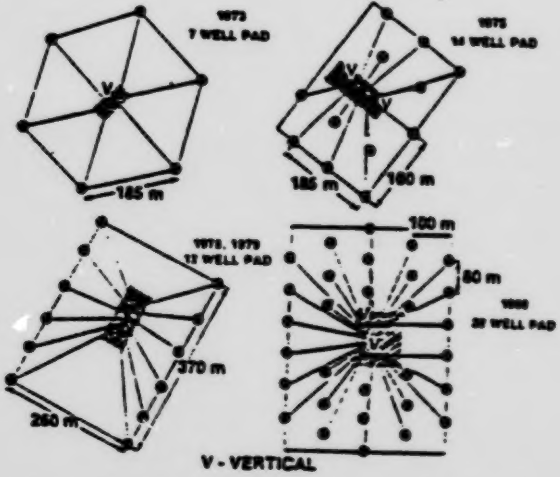

7 WELL PAD
185 m
14 WELL PAD
185 m
160 m
12 WELL PAD
370 m
260 m
100 m
80 m
WELL PAD
V - VERTICAL

Fig. 2. Evolution of the Cold Lake Pad Concept.

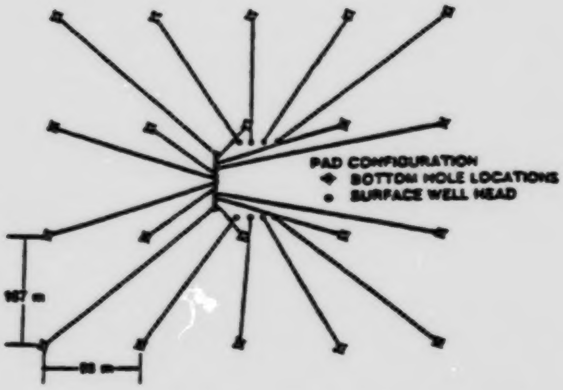

PAD CONFIGURATION
BOTTOM HOLE LOCATIONS
SURFACE WELL HEAD

Fig. 3. Cold Lake Project, 1981–83, 20 Well Pad.

3. COLD LAKE HORIZONTAL WELL

3.1. Drilling program

A schematic of the Cold Lake horizontal well design is shown in Fig. 4. A 311 m pilot hole was drilled to the kick off point at 46 m and an angle building assembly was picked up. The pilot hole was directionally drilled to 181 m measured depth (MD), opened to 445 mm and underreamed to 533 mm. Then 406 mm surface casing was run and landed at 167 m and cemented to surface.

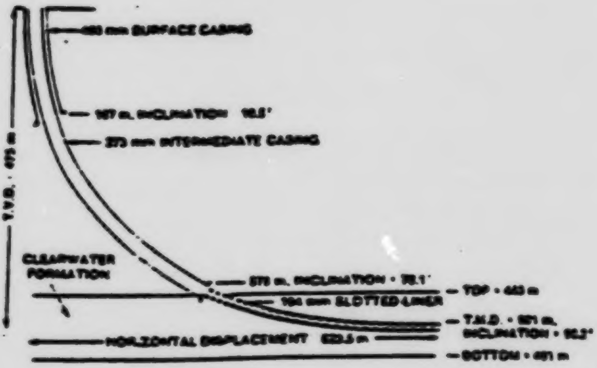

SURFACE CASING
INCLINATION
INTERMEDIATE CASING
T.V.D.
CLEARWATER FORMATION
INCLINATION
TOP
SLOTTED LINER
T.M.D.
INCLINATION
HORIZONTAL DISPLACEMENT
BOTTOM

Fig. 4. Well design.

A 241 mm pilot hole was then drilled to a depth of 591 m. This hole was reamed to 375 mm. Intermediate casing (273 mm) was set at the top of the Clearwater formation at 578 m (MD). The drift angle was 70.1°.

A 241 mm production hole was then drilled to a total measured depth (TMD) of 901 m at a final drift angle of 90.2°. Thus 323 m of near horizontal hole had been drilled past the intermediate casing point in the Clearwater formation. Final total vertical depth (FTVD) was 475 m with a closure of 623.5 m. A 194 mm slotted liner was run to bottom and hung inside the 273 mm intermediate casing. The liner was left uncemented.

A number of operational considerations affected drilling procedures:

- Kick off depth had to be as shallow as possible to minimize the rate at which angle was built due to the shallow depth of the producing formation—443 m TVD.
- Optimum hole size for directional drilling was 200–216 mm. This required a pilot hole, later opened to a larger size.
- Underreaming of the surface hole was necessary because the rig had a 445 mm rotary table. A 533 mm hole was required to accommodate 406 mm surface casing.

3.2. Drilling mud

Fresh water gel mud was used to drill the surface hole since filtrate seepage into fesh water sands close to surface prohibited use of an oil mud. A viscosity of 48 s/L was adequate to clean the surface hole during drilling, hole opening and underreaming.

After the surface casing was cemented, the drilling fluid system was displaced to an oil mud. The oil mud properties for different sections of the hole are shown in Table I. Oil mud was selected after lab tests indicated it would provide hole stability in the oil sands. Tests on the oil mud also indicated that it would reduce torque and drag compared to a water base mud. Connections throughout the pilot operations were tight because of the restricted circulation rate which had to be maintained through the downhole mud motor, limiting the annular velocity. This was corrected by raising the yield point to 9 Pa.

A shale shaker and 12 cone desilter were used while drilling the surface hole while the shale shaker and a centrifuge were used when oil base mud was run.

TABLE I

Oil mud properties

	INTERMEDIATE HOLE		PRODUCTION HOLE
	DEPTH - 577 m (PILOT)	DEPTH - 591 m (REAMED)	DEPTH - 863 m (MUD MOTOR)
MUD WEIGHT - kg/m³	970	1000	970
VISCOSITY - s/L	60	74	60
PV - mPa·s	22	28	20
YP - Pa	9	12	6.5
GEL STRENGTH - Pa	3.2/3.0	8.6/9.1	3.2/6.0
SOLIDS - %	3	6	4
OIL - %	76	74	75
WATER - %	21	20	21

3.3. Downhole tools

Conventional equipment was used for building angle (Fig. 5). This basic assembly, which varied only slightly for different sections of the hole, was used to pilot the surface and intermediate holes and drill the production hole. Bent subs (1.5°, 2° and 2.5°) or bent housing mud motors were used to build angle. A 165 mm downhole mud motor was used to drill both 311 mm and 241 mm pilot holes using a mill-tooth bit.

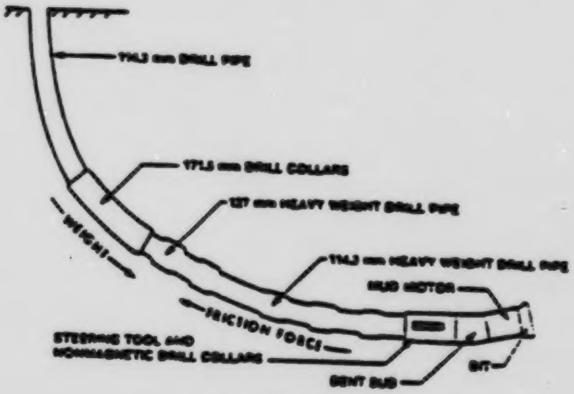

114.3 mm DRILL PIPE
171.5 mm DRILL COLLARS
127 mm HEAVY WEIGHT DRILL PIPE
WEIGHT
114.3 mm HEAVY WEIGHT DRILL PIPE
MUD MOTOR
FRICTION FORCE
STEERING TOOL AND NONMAGNETIC DRILL COLLARS
BIT
BENT SUB

Fig. 5. Angle building assembly.

Three non-magnetic drill collars were placed above the downhole mud motor to minimize magnetic interference by the drill pipe on the directional survey compass. This assembly was run in drilling to the 273 mm intermediate casing point. Four non-magnetic drill collars were then used to drill to final total depth.

A heavyweight drill pipe was run immediately behind the non-magnetic drill collars. Wall contact area was reduced by using heavyweight drill pipe which had a smaller outer diameter than the drill collars. This reduced the possibility of differential sticking. Steel drill collars were placed farther uphole in the near vertical section to more effectively provide bit weight.

3.4. Directional surveys

A comprehensive survey programme was carried out to achieve the necessary precision. A steering tool was used at all times while drilling a new hole. This tool consisted of a downhole directional sensing package located in the non-magnetic drill collars. It was connected by wireline to the surface, providing constant readout of hole direction and inclination. This enabled immediate corrective action to minimize severe doglegs.

Single shot magnetic surveys were run every 18 m. Magnetic multishot surveys were taken at every casing point. A gyroscopic survey was run inside the 273 mm intermediate casing to provide non-magnetic confirmation of the multishot surveys.

3.5. Casing and cementing

No problems were encountered in running and cementing surface and intermediate casing or while running the liner. A premium (slim line) liner connection was used to reduce drag. The liner was run without centralizers.

After the slotted liner was in place, remedial cementing work was needed to isolate 4.5 m of water-sand above the Clearwater sand not sealed off with the 273 mm casing.

3.6. Time analysis

An analysis of time spent on this well is shown in Table II.

TABLE II

Time analysis

OPERATION	TIME (DAYS)	% OF TOTAL
DRILLING	2.9	6.9
REAM HOLE TO LARGER SIZE	5.3	12.6
SURVEYS	3.8	9.0
TRIPPING	2.9	6.9
RUN CASING	3.5	8.3
W.O.C., HEAD UP, DRILL OUT	4.3	10.2
REAM TO BOTTOM	3.1	7.4
PROBLEMS - PLUG BACK SURFACE HOLE 3 TIMES	7.0	16.7
- REMEDIAL WORK ON LINER	7.0	16.7
- MISCELLANEOUS	2.2	5.3
	42.1	100%

3.7. Problems

A number of problems were encountered in the surface hole which took twice as long to drill as the targeted seven days. The original plan called for a 762 mm long bull nose to guide the hole opener in the pilot hole. The extended bull nose tended to bury itself in soft formations and initiate drilling of a new hole. It was found that a short non-rotating stabilizer ahead of the hole opener was best able to follow the pilot hole. This modified assembly was also used successfully in opening an intermediate hole.

The downhole mud motor was pulled at the surface cashing point. A slick string was run into the hole for a multishot survey. Severe bridging was encountered on the trip. Finally the multishot surveys were taken with the mud motor and bent sub downhole. All multishot surveys were run thereafter in this manner without problem.

3.8. Present status

The horizontal well has operated in a variety of experimental modes since 1978. Most of the testing used a vertical well for steam injection into the reservoir. The horizontal well was used as a flowing producer until mid-1982, when a conventional rod pump was installed. Results to date are encouraging and economic and technical evaluation of the project is continuing.

4. A DIRECTIONAL DRILLING CHALLENGE AT NORMAN WELLS

Esso Resources has embarked on a project to increase production from the Norman Wells oil field from 475 m^3/d to 4000 m^3/d. Approximately 154 wells are scheduled to be drilled by two rigs between July 1982 and September 1985. The shallow reservoir, remote northern location, and harsh winter climate make drilling at Norman Wells a challenge.

4.1. Reservoir

Hydrocarbons at Norman Wells are found in a Middle Devonian–Upper Devonian limestone reef complex which is 25 km long and 8 km wide. The Kee Scarp formation has a maximum thickness of 160 m and an average main reservoir thickness of 110 m. Vertical drilled depths to the pool vary from 385 m to 540 m. The reservoir dips at approximately 75 m/km to the southwest.

The reservoir has low matrix permeability (10 md or less) and an average pool porosity of about 12%. Natural fractures, which are an important feature of the reservoir, contribute little to total porosity but provide greater reservoir permeability. The fractures are vertical and commonly hairline. Orientation measurements indicate a general fracture trend for the pool at N 30° E.

4.2. Geographical location

Norman Wells is located 145 km south of the Arctic Circle at 65° N latitude. Magnetic problems caused by the small horizontal component of the Earth's magnetic field in high latitudes is a major concern while directional surveying. The high latitude also brings the problem of extreme winters when the temperature can dip to −45 °C. Compounding problems is freeze-up and break-up of the river during the autumn and spring which places severe timing constraints on drilling operations and logistics.

Seventy-five percent of the reservoir lies under the MacKenzie River (Fig. 6). This feature severely limits the drilling alternatives available.

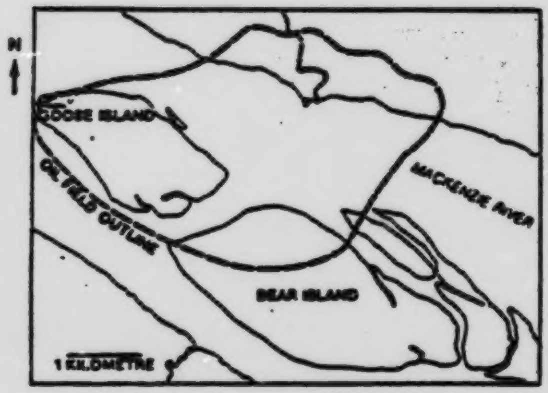


Fig. 6. Norman Wells oil field.

4.3. Alternatives

Two options were considered for infill development drilling of the Norman Wells pool.

(1) Build six artificial islands in the river supplemented by several pads on the natural land masses.

(2) Drill 30 horizontal wells and 20 directional wells from the natural land masses.

5. NORMAN WELLS HORIZONTAL WELL

Successful drilling of the Cold Lake horizontal well was a major factor in considering using horizontal wells for development of the Norman Wells field. It was decided to drill a horizontal test hole at Norman Wells since the required closure would be twice as large as that at Cold Lake for about the same true vertical depth.

5.1. Drilling programme

Figure 7 illustrates the well design. A 432 mm hole was drilled to kick off point at 30 m. An angle building assembly was employed to achieve a deviation rate of 5°/30 m in a 311 mm hole using a 197 mm mud motor. This 311 mm hole was drilled to 139 m TVD (143 m MD) where the drift angle was 15°. The hole was then opened to 432 mm with a bull nose hole opener. Then 339 mm surface casing was run and cemented to the surface.

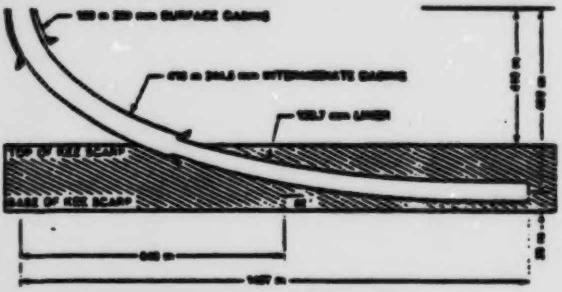


Fig. 7. Well design.

The 197 mm mud motor was again used below the surface casing to build angle at 5°/30 m in drilling a 311 mm hole. Drift angle achieved at 418 m TVD (top of the Kee Scarp formation) was 61°. Intermediate casing (244.5 mm) was run and cemented at this point. Drilling continued using a 165 mm mud motor with a 222 mm bit. A planned angle build rate of 2.5°/30 m was maintained until the drift angle was 86°. This angle was maintained to the final closure of 1407 m. A 139.7 mm liner was then run and cemented. At final total depth the well had a true vertical depth of 489 m, a closure of 1407 m and a drift angle of 90° with respect to the Kee Scarp. A total of 567 m had been drilled with a drift angle greater than 86°.

5.2. Bottom hole assembly

Figure 8 illustrates the build angle assembly. A bent sub (1.5°–3°), mud motor and a mill tooth bit were used to achieve the planned 5°/30 m angle build rate in the surface hole.

Non-magnetic drill collars were run above the bent sub to facilitate directional surveying. One non-magnetic drill collar was used in drilling the surface hole. Up to five non-magnetic drill collars were used

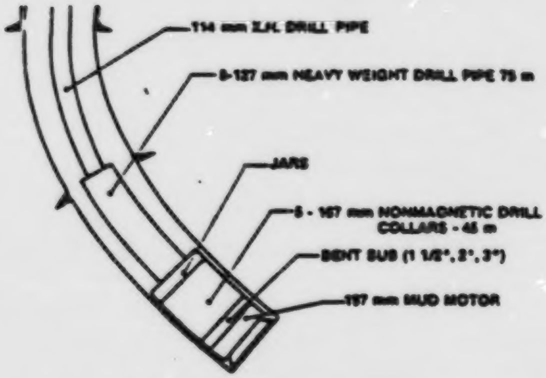

114 mm X.H. DRILL PIPE
9-127 mm HEAVY WEIGHT DRILL PIPE 75 m
JARS
5 - 167 mm NONMAGNETIC DRILL COLLARS - 45 m
BENT SUB (1 1/2°, 2°, 3°)
197 mm MUD MOTOR

Fig. 8. Build angle assembly.

thereafter. Steel drill collars were placed in the upper portion of the drill string in the horizontal section of hole. Heavyweight drill pipe again proved to be very effective in providing weight on the bit, while also reducing the wall contact area in the near horizontal section of the hole, thereby reducing the probability of differential sticking.

5.3. Drilling mud

Gel polymer mud was used to drill the surface and intermediate holes. Ten percent oil and other speciality products were used to provide lubrication and minimize torque and drag.

The drilling fluid was changed to an invert emulsion oil base mud after the intermediate casing was set. Properties of the oil base mud while drilling the near horizontal section of the hole are summarized in Table III.

TABLE III

Oil mud properties

MUD WEIGHT	910 - 1150 kg/m³
VISCOSITY	53 - 63 s/L
PV	25 - 60 mPa · s
YP	5 - 33 Pa
GEL STRENGTH	3/4 - 22/25 Pa
SOLIDS	1 - 16%
OIL	65 - 80%
WATER	10 - 24%

After switching to the oil base mud a desilter, desander and a centrifuge were used for solids control. It was found that this system was inadequate and solids content rose to 16%. A second centrifuge was then employed. This helped in controlling solids to a reasonable level while maintaining adequate mud properties.

5.4. Directional surveys

A survey system providing fast and accurate information was required in drilling with a planned angle build rate of 5°/30 m and a maximum inclination of 90°. The surveying problem was complicated since the oil field was located at a high latitude, approaching the magnetic North Pole.

The high inclination (90°) was a concern in gyroscopic surveying and the proximity to magnetic north was a concern in magnetic surveying. Although true magnetic field strength increases as one approaches the magnetic pole, horizontal field strength decreases because of the higher dip angle of magnetic lines of force. All magnetic survey tools measure or react to the horizontal field. The horizontal field strength at Norman Wells is 33% of that in the southern United States. This was an important concern since most survey tools are calibrated at southern latitudes.

The well was kicked off and drilled to the surface casing point using magnetic single shots. After running surface casing, a wireline steering tool was used to guide the drill string along the proposed wellbore path. The steering tool provided continuous readout of tool face orientation. This was important when using the 3° bent sub.

Prior to running intermediate casing, a magnetic multishot was run to confirm the single shot and steering tool surveys. Further confirmation of hole position was provided by a gyro run in intermediate casing to a point where the inclination was 60°. The surveys showed remarkably good agreement.

From intermediate casing point to final total depth, the steering tool was used as the primary survey tool with confirmation provided by single shot surveys. There was some concern expressed about the accuracy of the steering tool since the single shots sometimes indicated a 3°–5° discrepancy in azimuth. An analysis of survey data later indicated that the steering tool surveys when averaged provided the same bottom hole coordinates as the single shots. Azimuth fluctuations shown by the steering tool were attributed to the weak horizontal magnetic field at Norman Wells.

5.5. Cementing and logging

No problems were encountered in running and cementing surface and intermediate casing. Although a snubbing operation had been considered as a contingency in running the liner, this was not required.

Some problems were encountered in cementing the liner which was run on drill collars and heavyweight drill pipe using positive standoff centralizers run one per joint. The oil base mud was displaced to a water base mud prior to cementing the liner. A 5 m^3 water preflush was used. Friction reducer materials were added to the cement slurry.

Analysis of the liner cement job during completion operations indicated extensive communication along the liner. Cement bond logs were unavailable for analysis since the horizontal section of hole could not be logged.

5.6. Time analysis

An analysis of time spent on this well is shown in Table IV.

TABLE IV
Time analysis

OPERATION	TIME (DAYS)	% OF TOTAL
DRILLING	13.0	28.6
REAM HOLE TO 2 LARGER SIZES	0.5	1.1
SURVEYS	2.5	5.5
TRIPPING	11.1	24.4
RUN CASING LINER	2.0	4.3
W.O.C., HEAD UP, DRILL OUT	7.1	15.6
REAM TO BOTTOM	2.0	4.4
MISCELLANEOUS OPER. & PROBLEMS	6.0	13.2
LOGGING	1.2	2.6
	45.4	100%

5.7. Test well conclusions

Drilling and completions experience indicated that the horizontal wellbore was not compatible with reservoir depletion strategy. Since the reservoir was quite thick (150 m at the test location) vertical sweep from overlying and underlying strata was difficult because of three factors:

(1) Low matrix permeability.
(2) Natural vertical fractures present in the reservoir which frequently terminated at bedding boundaries.
(3) Induced hydraulic fractures could not provide the needed vertical continuity. Recent *in-situ* tests and field production performance data have shown that these fractures occur horizontally along bedding planes.

Thus, while the technical feasibility of drilling horizontal wells at Norman Wells was proven, depletion problems associated with this concept resulted in the use of artificial islands for development of the field. This decision was based on the following:

(1) The inability to effectively deplete the reservoir with a horizontal wellbore.
(2) Esso Resources' extensive knowledge from directional drilling at Cold Lake and Norman Wells.
(3) Esso Resources experience in building 18 artificial islands in the Beaufort Sea.

6. DIRECTIONAL DRILLING FROM ARTIFICIAL ISLANDS

Six artificial islands are currently being constructed to access reservoir target locations underlying the Mackenzie River that are beyond practical directional drilling limits from existing land masses. These islands will have a 80 m × 45 m working surface designed to accommodate the drilling rig, 20 wells, 30 man camp, heliport, and drilling supplies for 75 days. Wells on these islands will be drilled from trenches 60 m long × 2.5 m wide × 3 m deep recessed below pad level on a 2 m well spacing.

6.1. Drilling operations

All wells have been categorized into vertical and types I to III depending on their horizontal displacement at target depth (Table V).

TABLE V
Well categories

WELL TYPE	# WELLS	TARGET HORIZONTAL DISPLACEMENT (m)	MAX ANGLE	TVD (m)	MD (m)
VERTICAL	27	0-20	0-3	[illegible]	[illegible]
TYPE 1	30	21-270	4-40	[illegible]	[illegible]
TYPE 2	60	[illegible]	[illegible]	[illegible]	[illegible]
TYPE 3	31	[illegible]	[illegible]	[illegible]	[illegible]

Wells are classed as vertical provided their spud point overlays the target area which is defined for all well types as a 20 m × 40 m diameter ellipse. The directional wells have horizontal displacement targets varying from 21 m to 750 m.

Directional wells are programmed to kick off at 30 m. Type II and Type III wells build angle at 8°/30 m. Benefits of the high build rate are:

(1) The necessary high angles required to intersect the targets are attained over minimum drilled distances, thereby reducing total drilled meterage.
(2) The maximum angle required is minimized.

6.2. Drilling fluid

A gel water mud with viscosity control to 40–45 s/L is used to drill the surface hole. Production hole mud is built from the surface system with polymer additive as required for viscosity control and hole cleaning. Refinery byproduct bunker oil may be emulsified with lignosulphonate in concentrations of up to 10% as hole angle, torque and drag increase on type II and III wells.

6.3. Bottom hole assemblies

Positive displacement 171 mm downhole motors are used to drill 311 mm surface hole to casing point. A straight hole asembly is used to spud and drill out the conductor to kick off point (30 m) at which point bent subs varying from 0.5° to 4° are used to build the required angle. The programmed 8°/30 m build rates have been attained in the upper surface hole intervals with 3.5° and 4° bent subs. These were run in combination with straight hole mud motors.

6.4. Directional surveys

Continuous readout of survey data while drilling is provided through use of a measurement-while-drilling (MWD) tool. The tool, consisting of a downhole package of sensors (triaxial accelerometers and triaxial magnetometers), battery pack, and encoding unit is housed within a non-magnetic drill collar. The raw survey data are transmitted to the surface through negative pressure pulses in the drill string. The raw data are processed by computer into inclination, azimuth and toolface. Principal advantages of the MWD system include reduced survey time, increased accuracy, and compatibility with both rotary and motor drilling. Tandem single shots are routinely taken on bit runs.

Survey tool data are carefully monitored to ensure that the desired accuracy is attained. A downhole swing, consisting of four surveys taken at different tool face orientations at the same depth, is performed every 48 hours or whenever a new tool is picked up. The four surveys, after corrections for magnetic storms, must provide azimuth readings agreeing within ±1.5° and pass additional checks on the raw data.

6.5. Cementing and logging

Good quality cement jobs in deviated wells require the use of one centralizer per joint to provide adequate casing stand-off from the hole wall. The use of API standard centralizers for 177.8 mm casing in a 222 mm hole has caused extensive drag and slow running times. Recently, smaller, stiffer centralizers were used successfully on a type II well reducing casing running time from 2.4 days to 0.5 days.

The hole evaluation programme is contingent upon maximum well angle and proximity of the well to adjacent log/core data points. The running of open hole logs and cutting of oriented core has been restricted to vertical, type I and type II wells. Experience at Norman Wells has indicated that the upper limit for conventional free fall open hole logs is between 55° and 60°. Critical wells drilled with maximum angles up to 65° have been open hole logged with a 42.9 mm gamma/neutron pump down logging tool. This tool is pumped out of open ended drill pipe which has been tripped into the top of the reservoir. A cased hole gamma/neutron log is run for selection of completion intervals by the completion rig on those wells not logged open hole. The log quality and correlation with conventional open hole logs has been high, making the slim hole tool a contingency if the maximum wellbore inclination exceeds 57° or if conventional tools fail to reach bottom on the first attempt.

6.6. Drilling performance

Results on wells drilled to date have been very good. Type III wells which initially required 18 to 20 days to drill are now programmed for 12 days. Type I wells which formerly took 10 days are now targeted for 7.8 days. This represents an average of 40% time saving on the planned estimate which was based on wells drilled in 1979 and 1980. Additional rigs will not be required during the summers of 1983 and 1984 to complete the project as originally planned.

A comparison of actual versus planned parameters of wells E-29X (type I), G30X (type II) and H29X (type III) is provided in Table VI. A vertical projection of these wells is shown in Fig. 9.

7. CONCLUSIONS

Esso Resources Canada Limited today possesses the technology to routinely drill high angle (drift angles up to 90°) wells. The two horizontal wells drilled at Cold Lake and Norman Wells indicate that although the technology to drill these wells is present, the application of horizontal wells is dependent upon reservoir characteristics and the depletion strategy.

Norman Wells project drilling has also proved that angle build rates up to 8°/30 m are achievable on a routine basis. Directional surveying at high latitudes and high drift angles which was considered a problem is now routine and accurate due to advances in MWD technology. Considerable research and development is required in logging and cementing procedures for highly deviated holes.

TABLE VI

Actual performance of Norman Wells E-29x, G-30x & H-29x

	E-29x (TYPE I)		G-30x (TYPE II)		H-29x (TYPE III)	
	ACTUAL	PLANNED	ACTUAL	PLANNED	ACTUAL	PLANNED
WELL TYPE	1	1	2	2	3	3
K.O.P. (m)	30	30	30	30	30	30
MAX. ANGLE	18.75	14.0	63	58	75	80
ANGLE AT SURFACE CASING POINT	14	14.0	61.5	60	60	64
M.D. AT SURFACE CASING POINT	105	105	270	270	220	270
(AVERAGE RATE OF ANGLE BUILD OVER THE SURFACE HOLE INTERVAL (°/30 m)	3	3.25	6.4	5 TO 180 m M.D. 6,180 m - 270 m M.D.	5.8	8
TARGET TVD (m)	472	472	445	445	480	487
TARGET TMD (m)	482	482	654	671	917	985
TARGET HORIZONTAL DISPLACEMENT	85	80	457	455	700	700
OFFSET FROM TARGET CENTRE (m)	7.1	0	12.2	0	9.4	0
FTVD (m)	466	480	532	514	571	522
FTMD (m)	480	485	850	820	1132	1062
SPUD TO RIG RELEASE TIME (DAYS)	5.4	9.0	10.5	11.0	11.3	21.0

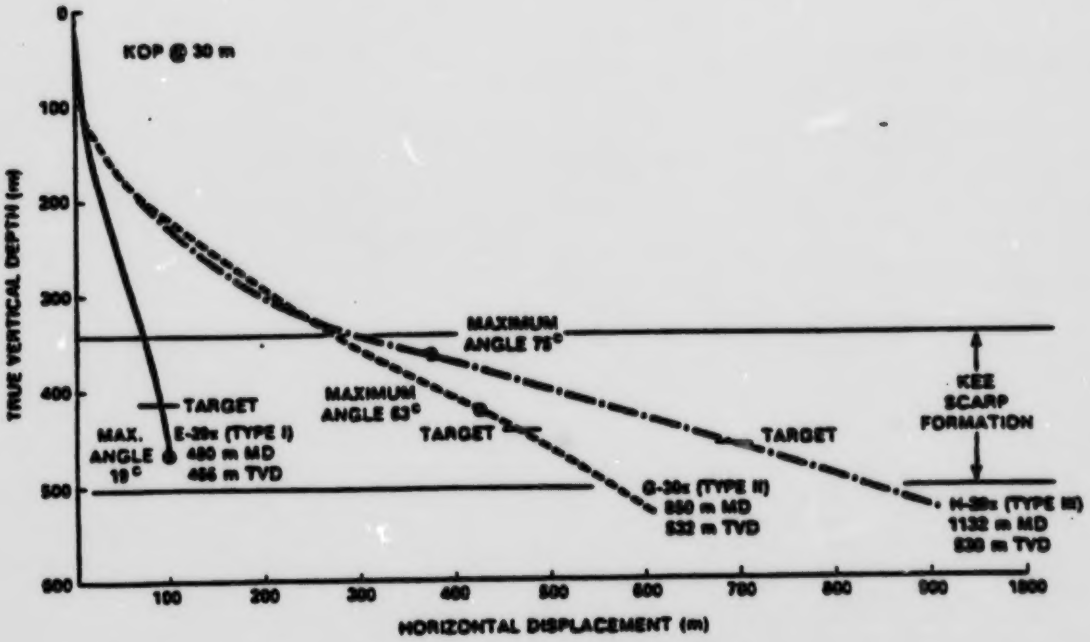


Fig. 9. Esso Norman Wells E-29X, G-30X, H-29X (Type I. II. III) vertical projection.

The excellent progress seen to date in the Norman Wells Expansion Project shows benefits of extensive pre-programme planning and the directional drilling experience gathered by Esso Resources Canada Limited.

ACKNOWLEDGEMENTS

The authors wish to express their appreciation to Esso Resources Canada Limited for permission to present this paper. They also wish to acknowledge the assistance of co-workers, especially Brian W. Smith, Darryl N. V. Butchko, Paul E. Atkinson, Doug A. Gust and Don G. Schaef.

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3. Mainland, G. G. and Lo, H. Y. *Technological Basis for In Situ Recovery of Cold Lake Bitumen,* 11th World Petroleum Congress, London, England; August 28, 1983.
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Oil Sands and Coal Department

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Planning Manager – Oil Sands

ESSO PLAZA 237 FOURTH AVENUE SOUTHWEST
CALGARY, CANADA T2P 0H6
(403) [illegible]-3737

August 20, 1984

(24)

APPLICATION REGISTERED
NO. 840870 DATE AUG 22 1984

Energy Resources Conservation Board
640-5th Avenue S.W.
CALGARY, Alberta
T2P 3G4

Attention Mr. R.G. Evans, Manager-Oil Sands

Dear Sir:

Re: Amendment to Approval No. 2943B

Esso Resources Canada Limited hereby requests the amendment of Approval No. 2943B (Leming Pilot), under Section 14(1) of the Oil Sands Conservation Act, to permit the further testing of the gravity assisted steam drive process in the Cold Lake Oil Sands deposit.

The proposed experimental scheme is expected to be operational for a minimum of ten years to obtain long term reservoir recovery data relevant to a gravity assisted steam drive process using a system of horizontal and vertical wells.

The proposed scheme is outlined in the attached documents. We have enclosed ten copies of the attachment for your convenience.

Please feel free to call me at 237-3455 or Mr. E.S. (Eric) Denbina at 237-3436 if you need further information.

Yours truly,

for D. Hunter
W. Jazrawi, P.Eng.

HNP/DGS:M

Attachment

SP1/1

ESSO RESOURCES CANADA LIMITED

OIL SANDS AND COAL DEPARTMENT

APPLICATION

FOR A

GRAVITY ASSISTED STEAM DRIVE PROCESS

IN SITU EXPERIMENTAL SCHEME

AT

SECTION 6-65-3W4

COLD LAKE, ALBERTA

Oil Sands Planning Division - Special Projects
August, 1984

SP1/3

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1. INTRODUCTION

This application describes a proposed modification to the Esso Resources Canada Limited Leming experimental oil sands recovery project (Approval 2943B), to obtain field performance data on a gravity assisted steam drive process using one horizontal well and an array of injection and observation wells. Bitumen production from the proposed horizontal well scheme will be applied to the existing Leming approval level of 2600 m^3/d.

The recovery process is expected to increase recovery efficiency significantly above the currently expected 20 percent using cyclic steam stimulation process.

Notwithstanding the knowledge still being gained from Esso's first horizontal well experiment in Leming as well as several years of laboratory work, significant technical and economic risks remain in developing this novel recovery process. These risks stem from uncertainties surrounding:

(i) the operation of multiple injectors and a long horizontal producer

(ii) drilling and completion of the long horizontal well

(iii) lifting high volumes of hot fluids from a highly deviated well

(iv) reservoir response to this process.

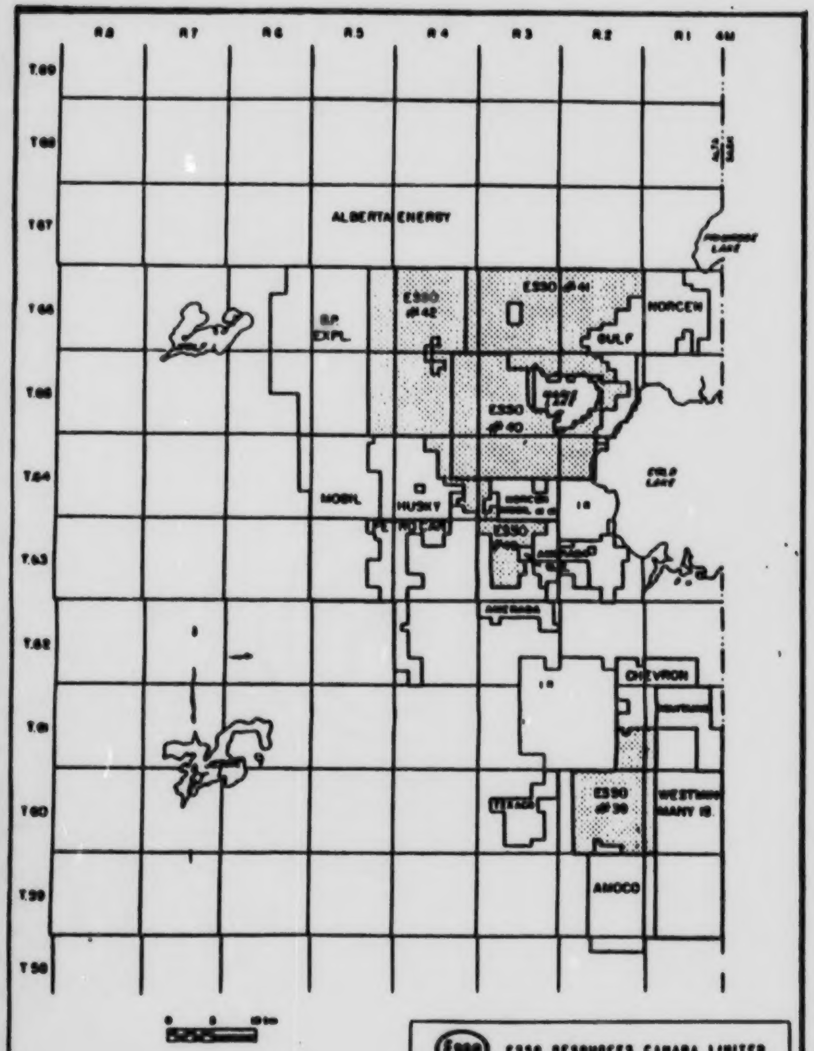
2. LAND OWNERSHIP

The proposed experimental scheme (hereinafter referred to as Horizontal Well Pilot II [HWP II]) will be conducted in the Clearwater formation in Section 6 of Township 65, Range 3, West of the Fourth Meridian, which is part of ERCL Oil Sand Lease (OSL) 40. This lease covers an area of 19,841 hectares with a 100% Esso interest as follows:

Lease Number	Issued Date	Expires	Area (ha)
Oil Sands Lease 40	December 24/68	December 24/89	19,841
P&NG 0478120245	December 21/78	Continued	5,632

All surface locations for the pilot well will be in Section 6. All leases in the area are Crown, with no land owners in the area. All trappers in the area have been notified.

Figure 2.1 shows the mineral resource ownership and Figure 2.2 shows the P&NG lease ownership in the area. The proposed location of HWP II is shown in Figure 2.3, relative to the May-Ethel Pilot plants and Cold Lake Production Project Phases I through IV.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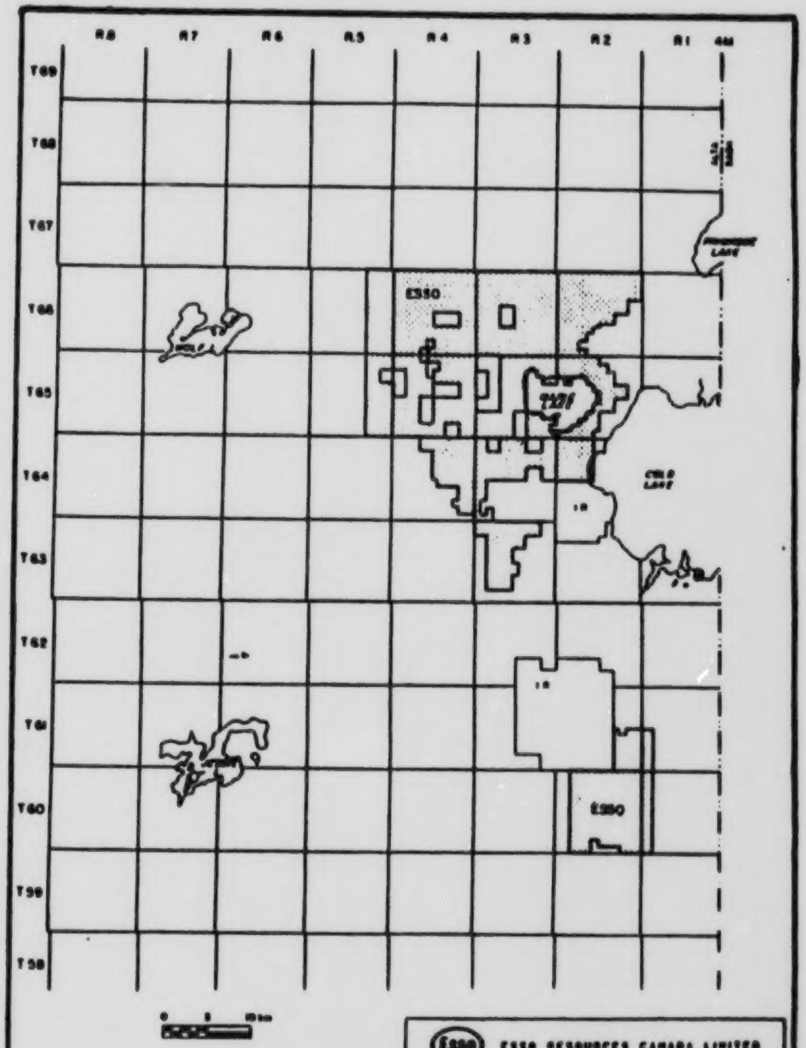
T58
ALBERTA ENERGY
BP EXPL.
ESSO #42
ESSO #41
ESSO #40
NORCEN
GULF
MOBIL
HUSKY
ESSO
CHEVRON
ESSO #39
WESTERN MANY IS.
AMOCO
TEXACO
COLD LAKE
0
5
10km

ESSO RESOURCES CANADA LIMITED

COLD LAKE AREA

OIL SANDS LEASES

FIGURE 2.1

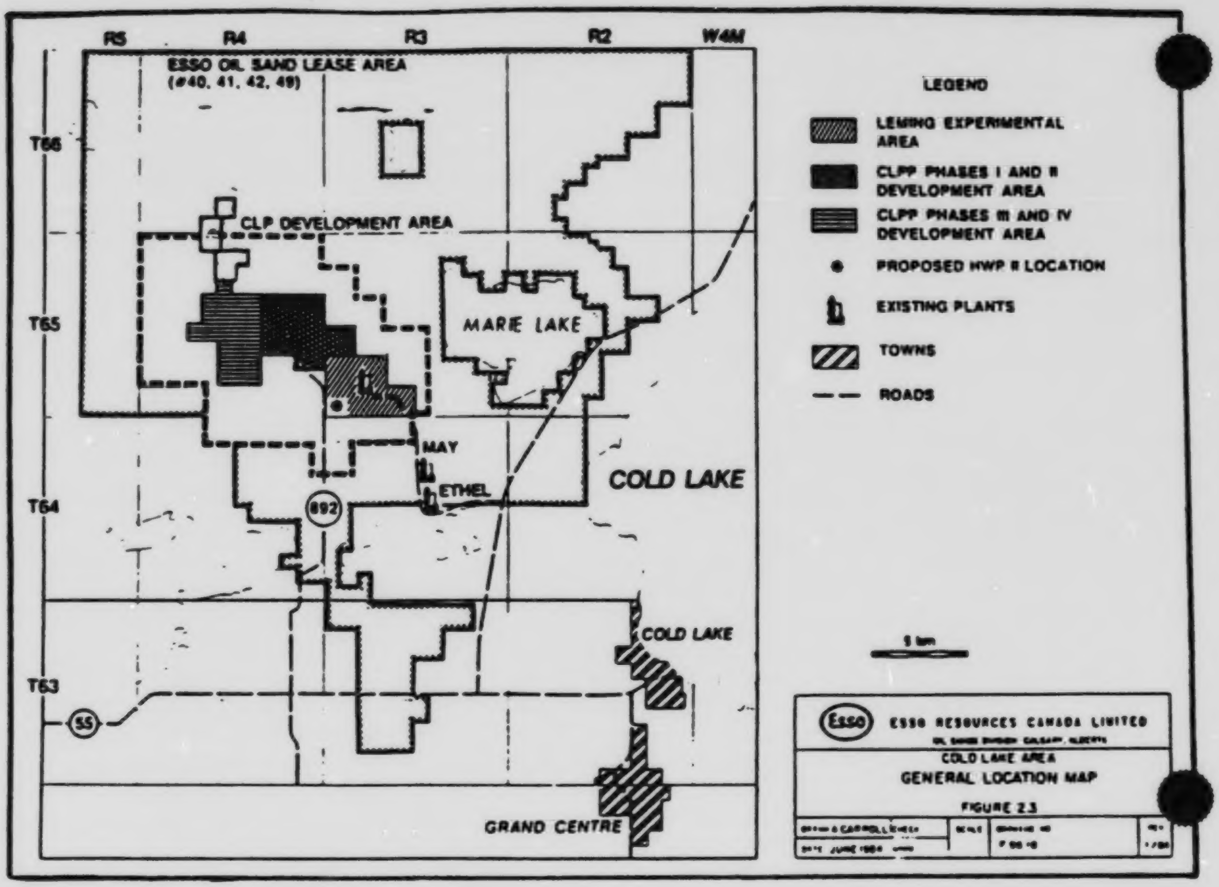

R8
R7
R6
R5
R4
R3
R2
R1
4M
T69
T68
T67
T66
T65
T64
T63
T62
T61
T60
T59
T58
ESSO
ESSO
COLD LAKE
0
5
10km

ESSO RESOURCES CANADA LIMITED

COLD LAKE AREA

P AND NG LEASES

FIGURE 2.2


R5
R4
R3
R2
W4M
T66
T65
T64
T63
ESSO OIL SAND LEASE AREA
(#40, 41, 42, 49)
CLP DEVELOPMENT AREA
MARIE LAKE
MAY
ETHEL
892
COLD LAKE
COLD LAKE
55
GRAND CENTRE
LEGEND
LEMING EXPERIMENTAL AREA
CLPP PHASES I AND II DEVELOPMENT AREA
CLPP PHASES III AND IV DEVELOPMENT AREA
PROPOSED HWP II LOCATION
EXISTING PLANTS
TOWNS
ROADS
5 km
Esso
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JUNE 1984

COLD LAKE AREA
GENERAL LOCATION MAP

FIGURE 2.3

3. REGIONAL GEOLOGY AND RESERVOIR DESCRIPTION

This section describes the general stratigraphy and geology of the Mannville Group and overlying formations in the vicinity of the proposed HWP II scheme in section 6-65-3 W4M. The proposed scheme will be conducted in the Clearwater Formation. Reference 1 provides a more regional geological description.

McMURRAY FORMATION

The McMurray Formation is a quartz-rich, fluvial-nearshore marine, sand sequence; unconformably overlying the Devonian Beaverhill Formation. In the vicinity of the proposed scheme, this formation is approximately 65 metres thick and is entirely water bearing. Excellent reservoir characteristics (i.e.: porosity, permeability and reservoir continuity) enable the applicant to utilize this zone for salt water disposal at wells 4-17-65-3, 11-7-65-3 and 14-5-65-3 W4M in the vicinity of the Leming Pilot. Figure 3.1 is a gamma ray cross-section of the McMurray Formation through the area of the proposed scheme.

CLEARWATER FORMATION

The Clearwater Formation is the main prospective reservoir in the area of Esso's Cold Lake leases. It is a fine to medium grained, sand rich, feldspathic litharenite; interpreted by the applicant to be a deltaic complex deposited in a shallow epeiric sea.

In the vicinity of the proposed HWP II scheme, the Clearwater occurs at an elevation of +184.0 metres and has a gross reservoir thickness of approximately 52.0 metres (see Figures 3.2 and 3.3). The net oil sand, utilizing a 6 wt.% cut-off, is 46.0 metres as shown in Figure 3.4. Summarized in Table 3.1 are the reservoir parameters describing this formation as derived from open hole well logs and core analysis data.

Directly overlying and underlying the Clearwater reservoir are laterally continuous shale beds of the Lower Grand Rapids and McMurray Formations. These shale beds are 3.0-9.0 metres thick and are illustrated in a two well, gamma ray log, cross-section in Figure 3.5. Based on Leming Pilot experience, these shales are interpreted to be relatively impermeable and will inhibit interformational flow.

LOWER AND UPPER GRAND RAPIDS FORMATIONS

Overlying the Clearwater Formation are the Lower and Upper Grand Rapids Formations. These formations consist of interbedded sands and shales and are bitumen bearing in part.

Figure 3.6 is a gamma ray log cross-section of the Lower Grand Rapids Formation. This formation has a thick water sand in its basal portion which exhibits good vertical and lateral continuity. Overlying this water sand are 5.0-7.5 metres of net oil sand situated in thin, discontinuous lenses.

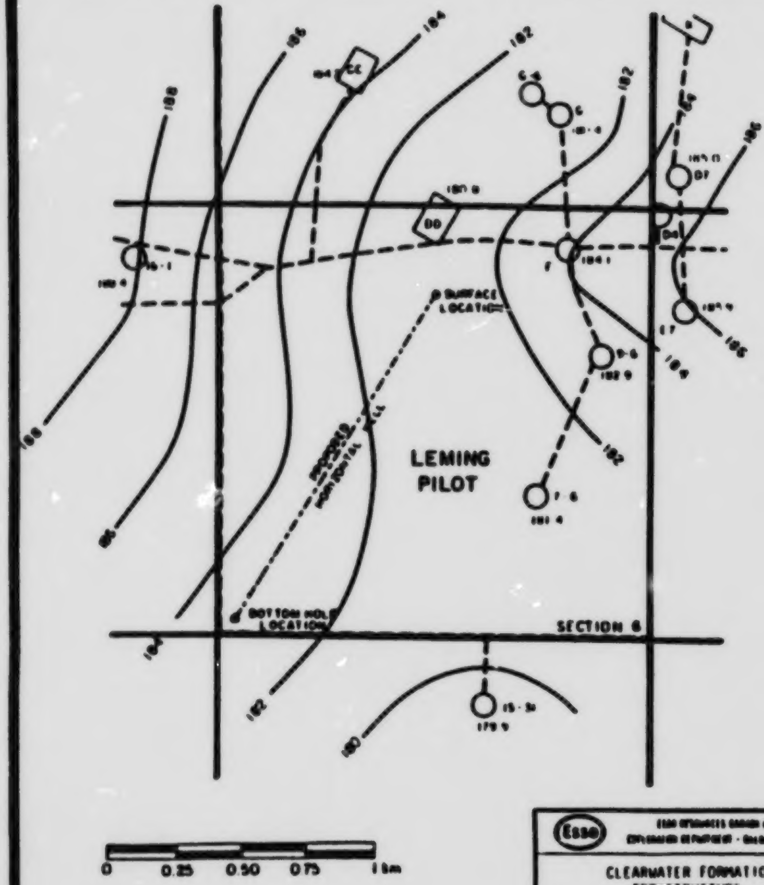
Figure 3.7 is a gamma ray log cross-section of the Upper Grand Rapids Formation from the proposed pilot area. This formation consists of thin, laterally discontinuous lenticular sands that contain both bitumen and water. The net oil sand for this formation is approximately 5.0-14.5 metres.

COLORADO GROUP

Overlying the Upper Grand Rapids Formation are 170 metres of organic rich shales and minor silt beds of the Colorado Group. This package of fine grained sediments is interpreted to represent a major regional aquitard in the Cold Lake area.

GLACIAL DRIFT

Approximately 150 metres of glacial drift unconformably overly the Colorado Group in the vicinity of the proposed pilot. The drift consists predominantly of tills (aquitards) and lesser amounts of channel sands and gravels (aquifers). Three drift aquifers; the Durlingville Formation, the Beaver River Formation, and a surface aquifer are interpreted to be present in section 6. Figure 3.8 illustrates the expected vertical geometry of the aquitards and aquifers in this section.

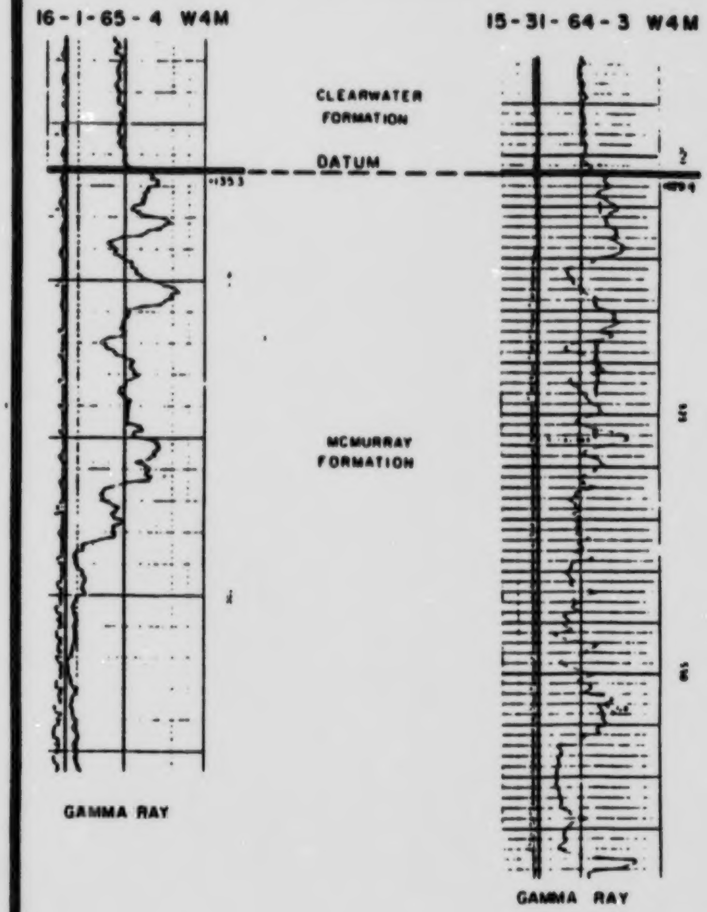

188
186
184
182
180
LEMING
PILOT
SURFACE LOCATION
BOTTOM HOLE LOCATION
SECTION 6
15-31
179.9
DD
0
0.25
0.50
0.75
1 km

Esso

CLEARWATER FORMATION
TOP STRUCTURE

C.I. 2m Sec.6-65-3W4M

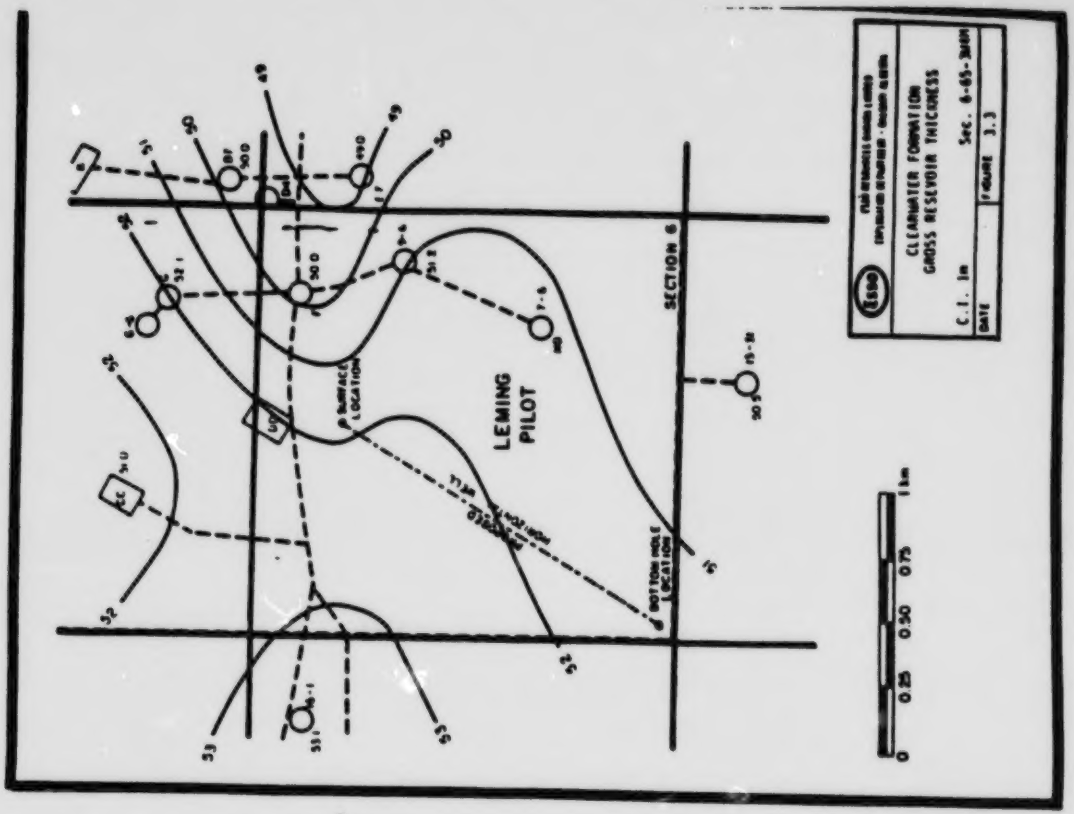
DATE FIGURE 3.2

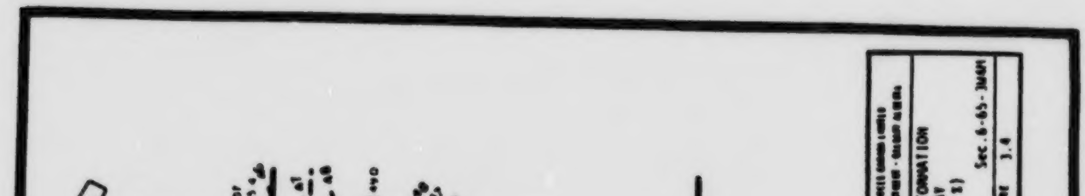


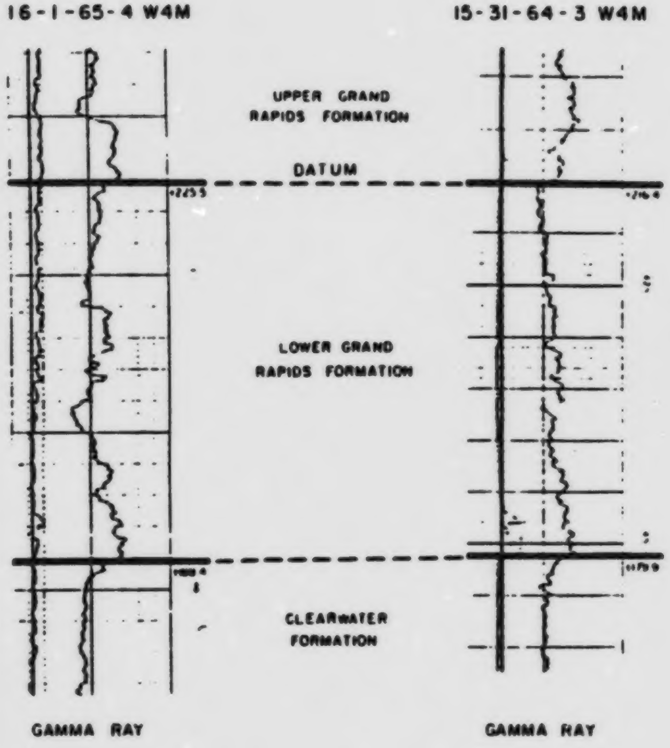
Esso

McMurray
Formation
Log Section

DATE FIGURE 3.1


CLEARWATER FORMATION
GROSS RESERVOIR THICKNESS
C.I. 1m
Sec. 6-65-3W4M
DATE
FIGURE 3.3
LEMING PILOT
SECTION 6
SURFACE LOCATION
BOTTOM HOLE LOCATION
PROPOSED HORIZONTAL WELL
0
0.25
0.50
0.75
1 km
49
50
51
52
53


CLEARWATER FORMATION
NET PAY
(>6 wt %)
C.I. 1m
Sec. 6-65-3W4M
DATE
FIGURE 3.4
LEMING PILOT
SECTION 6
SURFACE LOCATION
BOTTOM HOLE LOCATION
PROPOSED HORIZONTAL WELL
0
0.25
0.50
0.75
1 km
46
47
48

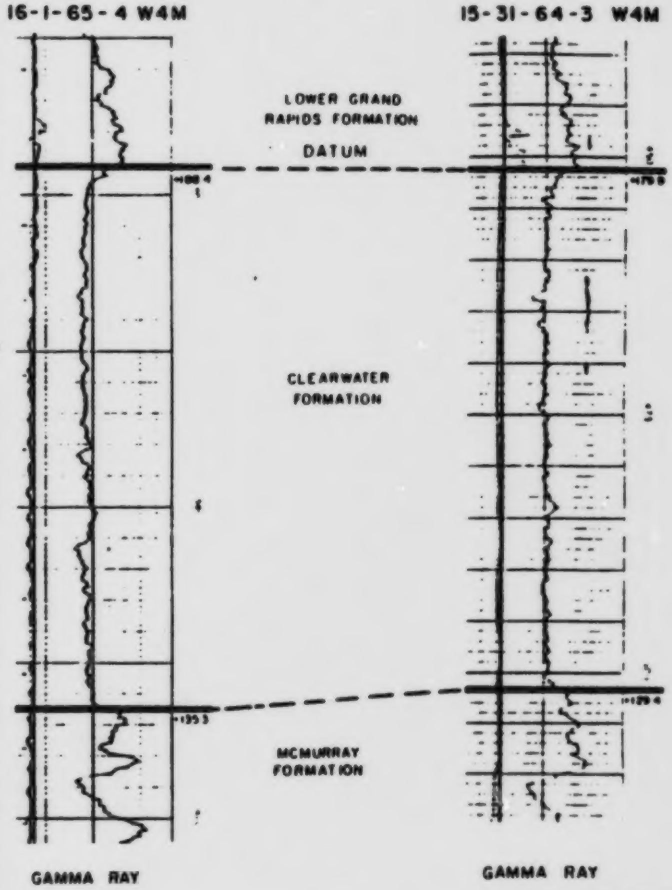


Lower Grand Rapids Formation

Log Section

DATE

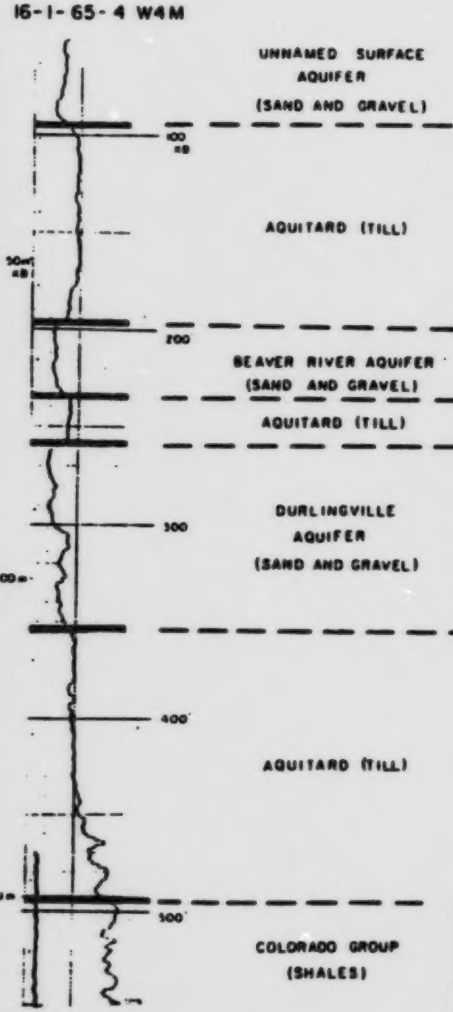
FIGURE 3.6



Clearwater Formation Log Section

DATE

FIGURE 3.5

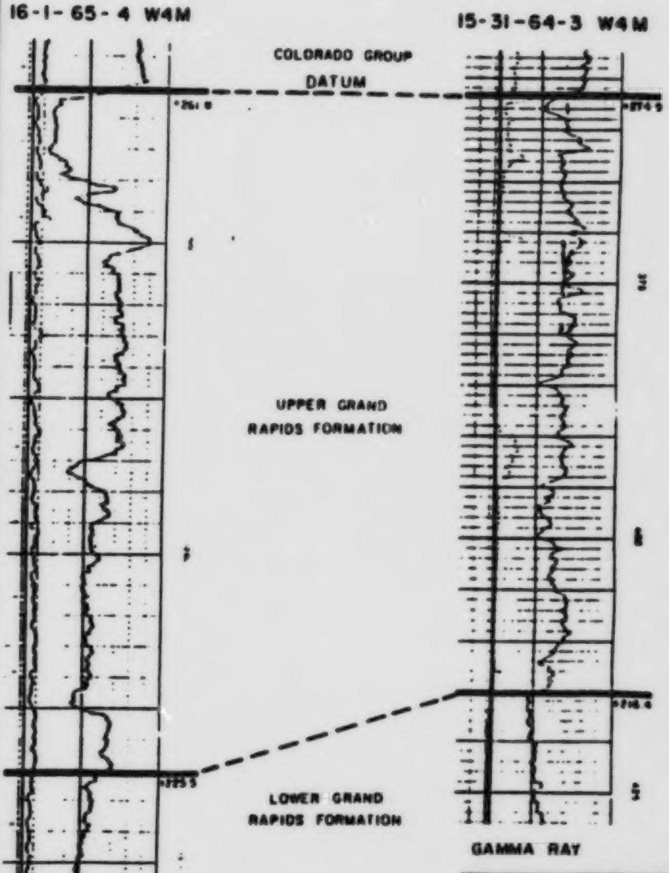


Esso
[illegible]
[illegible]

Glacial Drift
Hydrostratigraphic Log
Section
Gamma Ray Curve

DATE

FIGURE 3.8



Esso
[illegible]
[illegible]

Upper Grand
Rapids Formation
Log Section

DATE

FIGURE 3.7

TABLE 1

CLEARWATER FORMATION RESERVOIR PROPERTIES - SEC. 6-65-3 W4M

AVERAGE RESERVOIR DEPTH	- TOP	+ 184.0 m
	- BASE	+ 133.0 m
GROSS RESERVOIR THICKNESS		51.0 m
NET OIL SAND (6 wt.% cut-off)		46.0 m
NET:GROSS RATIO		0.90
AVERAGE POROSITY		33%
AVERAGE WEIGHT PERCENT BITUMEN		10.0%
ISOLATING BARRIERS	- GRAND RAPIDS/CLEARWATER	5.0 m
	- CLEARWATER/McMURRAY	3.0-9.0 m

4. RECOVERY PROCESS

The recovery process to be tested will be gravity drainage assisted steam drive. This process has been previously described in publications by Esso(2-6).

Initially, there will be one production and two injection wells, as well as two to four process monitoring wells. Steam will be supplied from the Leming pilot and the produced fluids treated at the Leming pilot facilities.

The experimental scheme will test:

(i) process performance
(ii) multiple injector operation
(iii) early start-up operation
(iv) drilling and completion of a 1000 metre long horizontal well
(v) lifting high volumes of hot fluids from the horizontal well.

5. PROJECT SCOPE

(I) Well Site Production Facilities

The project ~~is~~ comprised of up to seven wells drilled from three pads, all located in Section 6-65-3W4 (See Figure 5.1).

Production from the horizontal well will be gathered near the Leming DD Pad satellite manifold; production rates are discussed in Section 8. A new three-phase test separator will be installed to facilitate the measurement of produced fluids (Figure 5.2) The satellite facilities design will be similar to existing facilities, with the following main components:

- a steam distribution manifold
- three-phase test separator
- a vent separator, tank and stack

Since the test separator is dedicated to service only the horizontal well, oil and water production rates will be monitored continuously. A turbine meter and capacitance probe, in conjunction with a net oil analyzer, will be used on the oil leg, and a turbine meter and totalizer will be used on the water leg.

An orifice plate and chart recorder will be installed on the vent gas line (between the vent separator and vent tank) to measure the gas vent rates.

The steam injection rates will be measured at each well using a flow nozzle and chart recorders.

(II) Steam Supply

The steam generation facilities at the existing Leming plant were recently expanded by the installation of an additional steam generator rated at 18,100 Kg/hour of approximately 80% quality steam at 14.1 MPa. The new generator, B-111L, will provide the additional steam capacity required for the start-up of Leming Q/S infill pad and HWP II. The generator was started up during August, 1984.

(III) Water Supply

Since the Leming plant is to be the steam supply source, its existing water supply will be used in the current configuration. Plans are to continue fresh water withdrawal from Ethel Lake and Cold Lake, within the approved license allocation of 7.2 x 10^6 m^3/year. No additional fresh water allocation is required.

(IV) Water Disposal

Produced water will either be

(i) reused for steam generation after treatment at the Leming or CLPP water reuse plants

or

(ii) injected in McMurray or Cambrian disposal wells

(V) Produced Fluid Handling

Production from HWP II will be gathered near the Leming DD Pad and directed to the Leming Plant in the same manner as the existing Leming pilot wells. The oil-water separation equipment capacity at the Leming Plant is currently being expanded through the installation of a Slop Oil Treater, scheduled for completion by September, 1984. The additional capacity gained from this expansion will be sufficient to handle the additional production.

(VI) Pipeline

From the Leming Plant, the produced bitumen will be diluted with condensate to reduce its viscosity and pipelined to market through the Alberta Energy Company Ltd. pipeline system.

(VII) Future Expansion

Initially, in the first phase of operation, only two injectors will be used in the scheme, situated above the first 500 metres of the horizontal well. However, a design allowance has been made to tie in two additional steam injection ~~wells~~ in 1987. These wells are part of the second phase of the HWP II development plan, which is to activate the remaining 500 metres of horizontal well (See Figure 5.1 [Pad 4]).

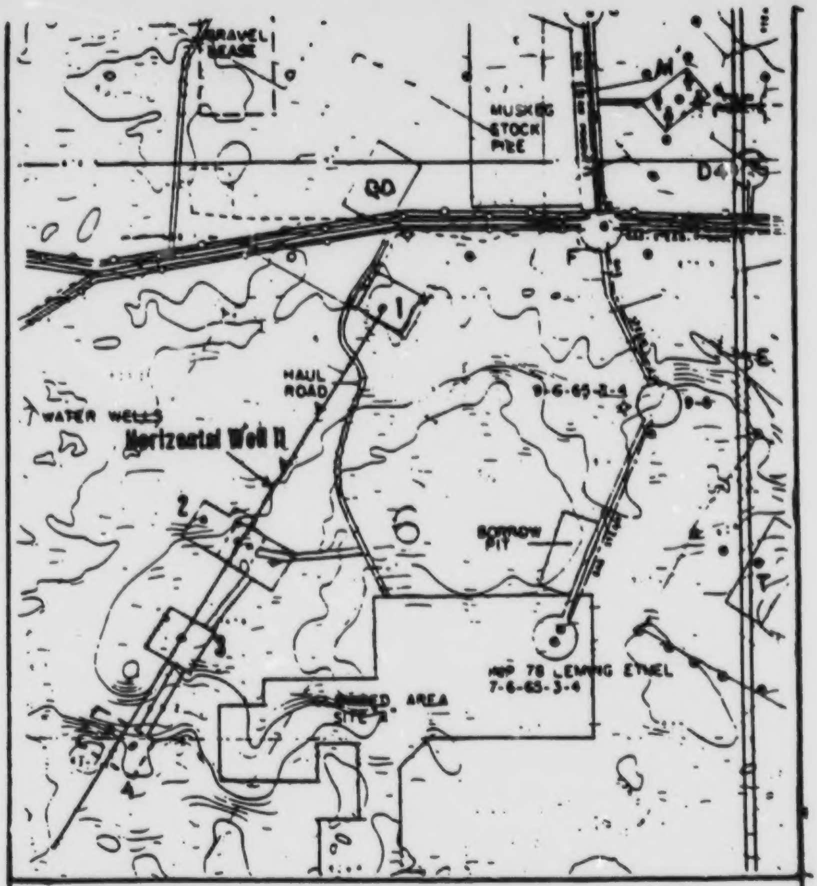

GRAVEL LEASE
MUSKEG STOCK PILE
QD
D4
F
1
E
HAUL ROAD
WATER WELLS
Horizontal Well II
2
3
4
6
BORROW PIT
HOP 78 LEMING ETHEL 7-6-65-3-4
CLEARED AREA SITE

Figure 5.1 Horizontal Well Location

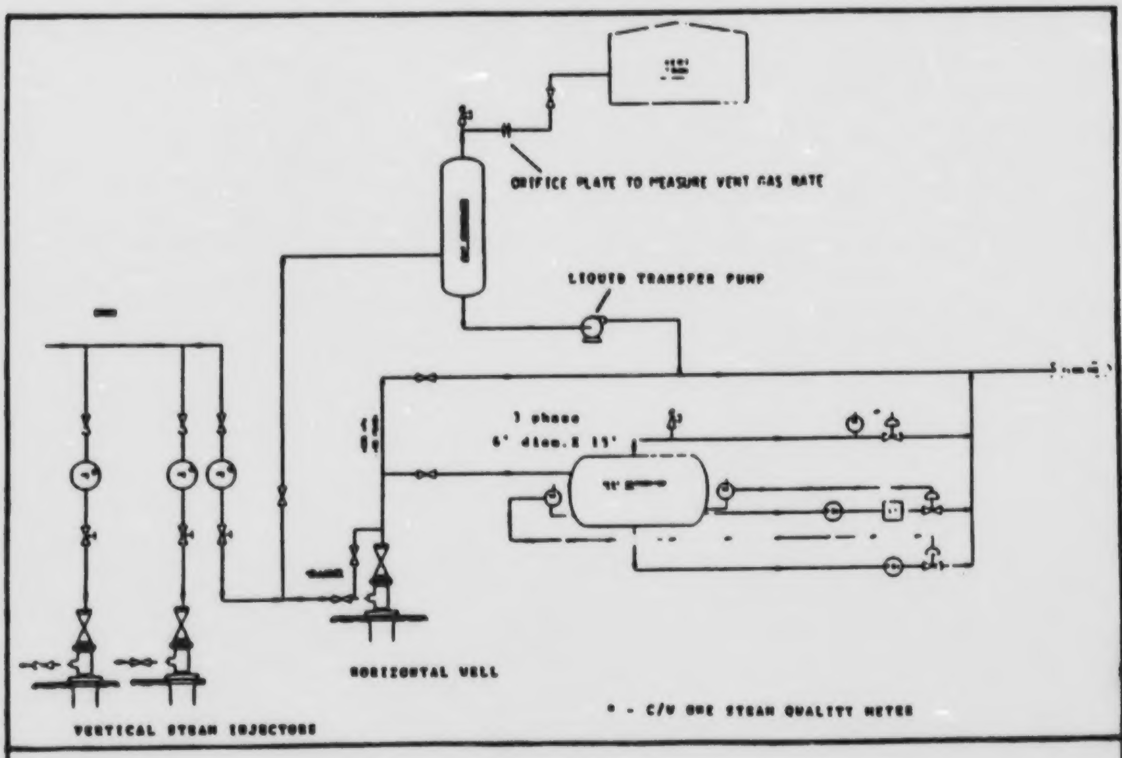

ORIFICE PLATE TO MEASURE VENT GAS RATE
LIQUID TRANSFER PUMP
3 phase
6' diam.X 15'
HORIZONTAL WELL
VERTICAL STEAM INJECTORS
* - C/W ONE STEAM QUALITY METER

Figure 5.2 Process Flow Diagram

6. WELL COMPLETIONS

(I) Drilling Completions

Up to total of seven wells will be drilled and completed as part of the proposed scheme. Provided in Table 6.1 are the details for well casing and cementing designs. A general description follows:

1) The horizontal well will be equipped with:
   - o 762 mm conductor pipe cemented at 22 m KB
   - o 508 mm surface pipe cemented at 150 m KB (i.e., below Glacial Drift)
   - o 339.7 mm production casing cemented to surface with thermal cement, landed within 5-7 metres of the bottom of the Clearwater zone

Following the setting and cementing of the 339.7 mm production string, a 1000 metre long 250.8 mm horizontal hole will be drilled using a downhole motor drilling assembly and a 193.7 mm production liner run in.

The casing and liner are designed based on start-up steam injection pressure of 8 to 12 MPa with a resulting maximum temperature of 325°C. The average long range operating pressures are in the range of 2 to 8 MPa with average temperatures of 215 to 295°C

(I) Drilling Completions (Cont'd)

2) The support wells (two steam injectors, two temperature observation wells and possibly two seismic observation wells) will be completed using 406 mm conductor pipe cemented at 20 m KB and 177.8 mm production casing cemented to surface with thermal cement.

Figure 6.1 shows a cross sectional view of the horizontal well, steam injector, and observation and seismic well configuration.

(II) Production Completions

The horizontal well will be completed with a 114.3 mm tubing string (complete with pump seating nipple) landed at approximately 720 m KB. A 60.3 mm bubble tube string will also be run to the mid-point of the 1000 metre horizontal run; i.e., 1220 m KB (see Figure 6.1). An 88.9 mm bottom hole pump driven by a surface pump unit will then be installed. The wellhead will be designed for 20.7 MPa working pressure (see Figure 6.2 for wellhead details).

(II) **Production Completions** (Cont'd)

The steam injectors will be completed using 73 mm or 88.9 mm tubing. A theromocouple string will be run on the outside of the casing string. Steam will be injected down the tubing and the casing annulus will be used for pressure measurement.

The two observation and two seismic wells will not be perforated and no tubing will be run.

HORIZONTAL WELL PILOT II

Figure 6.1

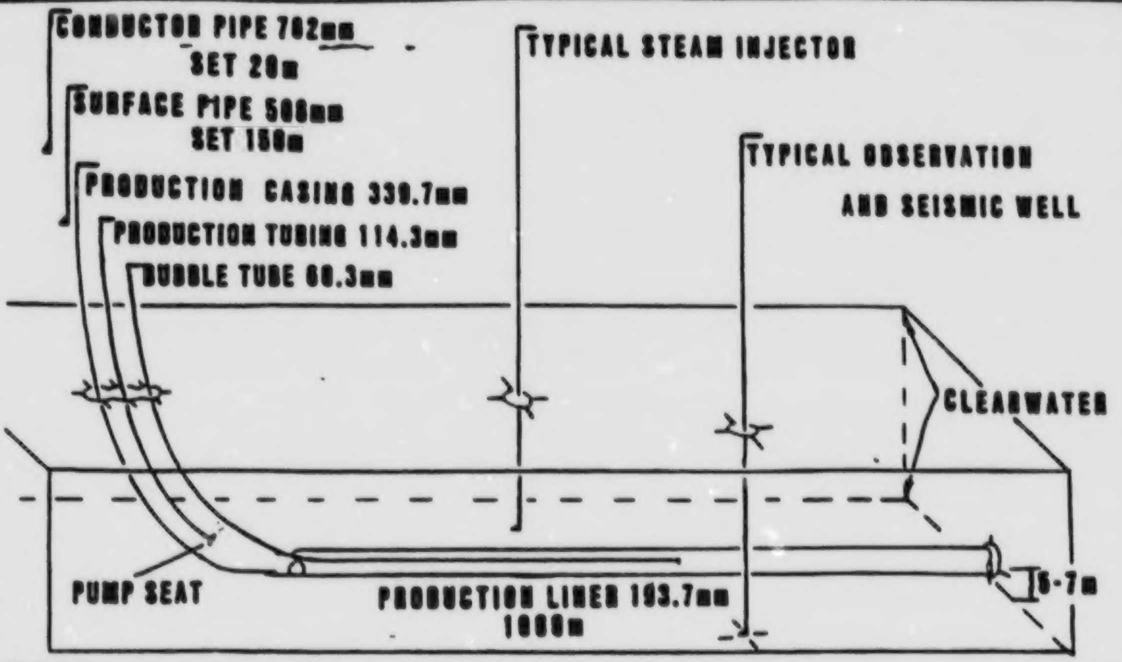
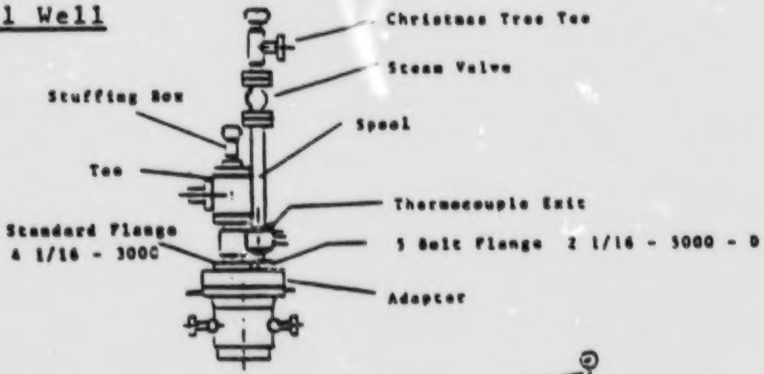

CONDUCTOR PIPE 762mm
SET 20m
SURFACE PIPE 508mm
SET 150m
PRODUCTION CASING 339.7mm
PRODUCTION TUBING 114.3mm
BUBBLE TUBE 60.3mm
TYPICAL STEAM INJECTOR
TYPICAL OBSERVATION
AND SEISMIC WELL
CLEARWATER
PUMP SEAT
PRODUCTION LINER 193.7mm
1000m
5-7m

Figure 6.2

Horizontal Well Pilot II - Wellhead Designs

Horizontal Well


Christmas Tree Tee
Steam Valve
Stuffing Box
Spool
Tee
Thermocouple Exit
Standard Flange
4 1/16 - 3000
5 Bolt Flange 2 1/16 - 3000 - D
Adapter

Vertical Well

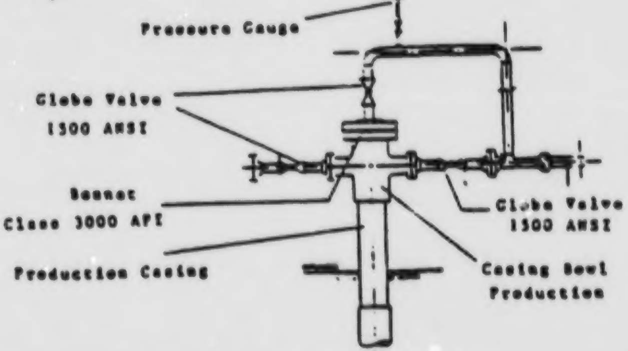

Pressure Gauge
Globe Valve
1500 ANSI
Bonnet
Class 3000 API
Globe Valve
1500 ANSI
Production Casing
Casing Bowl
Production

TABLE 6.1

HORIZONTAL WELL PILOT II

WELL CASING DESIGNS

WELL NAME	CASING	SIZE	SPECIFICATION	SET AT	CEMENT
Horizontal Well	Conductor Pipe	30"	762 mm x 11.1 mm WT, API 52 Grade B, Bevelled for Welding	20 m	Class G
	Surface Casing	20"	508 mm x 11.1 mm WT, API 5L Grade X52, c/w Vetco VP-3 Connectors	150 m	Class G
	Production Casing	13 3/8"	339.7 mm x 107.1 kg/m L80 Seamless c/w BT+C IOSI	5-7 m from bottom of CL zone	Thermal Cement
	Production Liner	7 5/8"	193.7 mm x 39.3 kg/m K55 Seamless c/w Hydrill Triple Seal Threads	1000 m Horizontal Run	--
		5 1/2"	139.7 mm x 20.8 kg/m K55 Seamless c/w Hydrill Triple Seal Threads	Contingency Only	--
Steam Injectors (2)	Conductor Pipe	16"	406 mm x 8.0 mm WT, Bevelled for Welding	20 m	Class G
	Production Casing	7"	177.8 mm x 34.2 kg/m, L80 Seamless c/w BT+C IOSI	Bottom of CL Zone	Thermal Cement
Observation Wells (2) and Seismic Wells (2)	Conductor Pipe	16"	406 mm x 8.0 mm WT, Bevelled for Welding	20 m	Class G
	Production Casing	7"	177.8 mm x 34.2 kg/m, L80 Seamless c/w BT+C IOSI	Bottom of CL Zone *	Thermal Cement

* Note the first observation well will be drilled into the McMurray Formation.

7. MONITORING SYSTEM

The monitoring system (Figure 7.1) for the scheme is designed to provide information on the performance of the in situ process, especially the validation of steam chamber development.

The horizontal well will be instrumented with a bubble tube to measure bottom hole pressure and a series of thermocouples in the bubble tube to measure the development of the steam chambers along the well.

Each of the two injectors, V1 and V2, will be instrumented to measure bottom hole pressure and thermocouples to measure bottom hole temperatures. These systems, along with those in the horizontal well, will be used to obtain pressure and temperature fall-off data which is expected to provide information on the steam chamber volume.

Two temperature observation wells, O1 and O2, are strategically located and will monitor, with thermocouples, the passing of the steam chamber front past their locations. Well O1 will monitor the movement perpendicular to the horizontal well, providing design information on spacing of future horizontal wells in a repeated pattern.

7. MONITORING SYSTEM (Cont'd)

Well 02 will monitor the chamber front movement along the production direction, providing design information on spacing of the vertical injectors.

About 27 surface benchmarks will be placed in an extended H-array, 400 metres past the extremities of the injector well system. They will be placed 100 metres apart, and periodic level surveys will determine any ground uplift and lateral movement during pilot operation. The measured response will be used to help in chamber volume determination and will give information on process dynamics.

High resolution surface reflection seismic will be carried out periodically along the benchmark lines and a little beyond. Reflection seismic, which detects anomalies such as gas zones, is expected to help in delineating the areal extent of the steam chamber and map its growth with time.

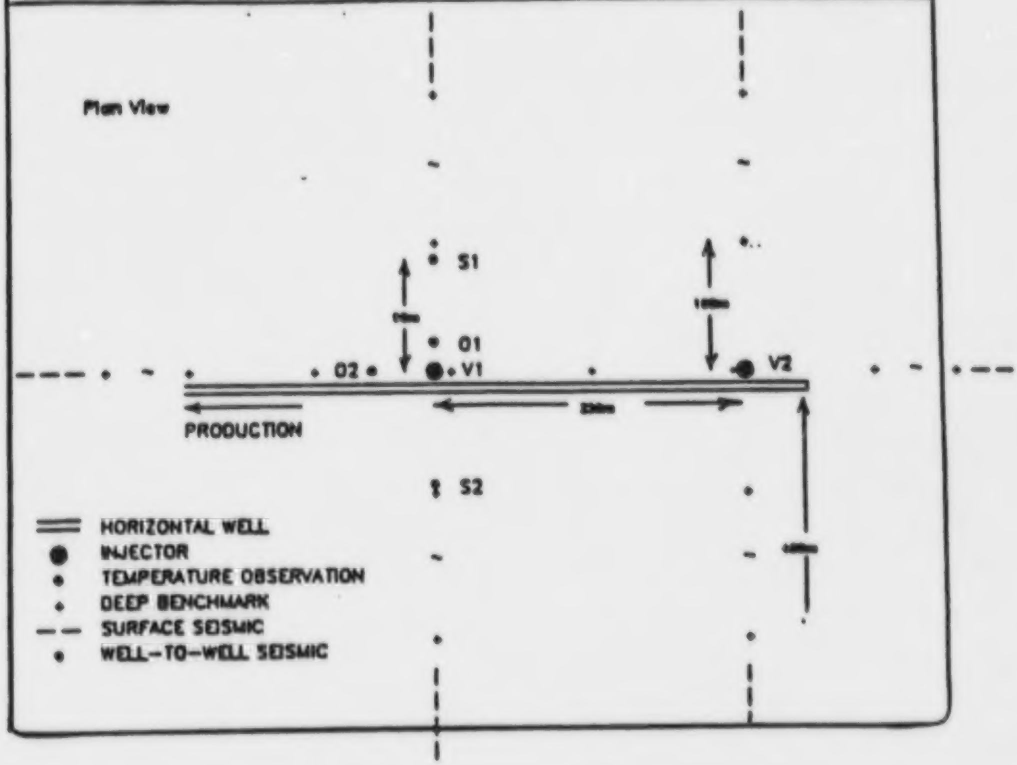
Two wells, S1 and S2, on opposite sides of the horizontal well in a direct line with one of the injectors, will be used for well-to-well seismic measurements to help provide a cross sectional view of the growth of the steam chamber.

A special steam quality measurement meter will be used to determine steam quality into the two steam injectors and the horizontal well.

Possible casing failures in injection and production wells will be monitored by observing the relationship between steam injection pressures and volumes daily, conducting temperature surveys of the wellbore and regularly comparing each well's performance with a computer model of a similar well.

Figure 7.1

HORIZONTAL WELL PILOT II MONITORING SYSTEM


Plan View
S1
O1
O2
V1
V2
S2
PRODUCTION
HORIZONTAL WELL
INJECTOR
TEMPERATURE OBSERVATION
DEEP BENCHMARK
SURFACE SEISMIC
WELL-TO-WELL SEISMIC

8. FORECASTS

A forecast of anticipated oil production, steam injection and water production on a yearly average basis to 1990 for the proposed experimental scheme is shown in figure 8.1. This forecast reflects the anticipated future expansion of HWP II described in Section 5(VII). As the project carries with it the degree of uncertainty inherent in an experimental scheme, forecasted profiles may vary from those shown in Figure 8.1.

Bitumen production is expected to reach approximately 50-100 m^3/day by 1987 and average about 120 m^3/day thereafter. Steam requirements and water production are based on expected OSR and WOR forecasts and are therefore driven by the bitumen production forecast.

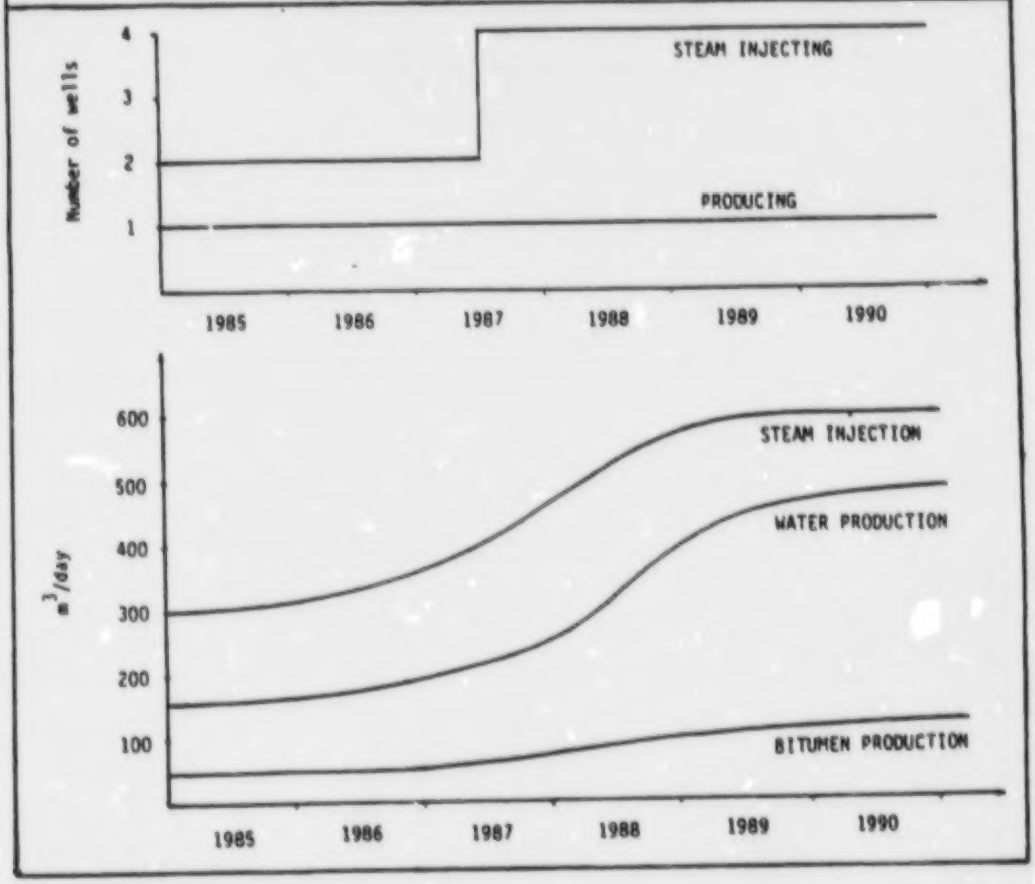
Vent gas production is estimated to reach approximately 490 standard m^3/day (reflecting solution GOR of 9.8 m^3/m^3 based on PVT properties of the reservoir fluids) for the first three years of operation. After 1987, vent gas volumes are expected to approximately double to 1180 standard m^3/day.

Sand production is expected to be negligible due to the low differential pressures across the liner completion.

Figure 8.1

FORECASTS

HORIZONTAL WELL PILOT II PROJECT



9. ENVIRONMENTAL IMPACT

The following is a summary of environmental considerations relative to the proposed horizontal well pilot.

I. Atmospheric Emissions

Atmospheric emissions from the project will result from the release of vent gas at the well pad location and incremental flue gas discharge from the new steam generator stack at the Leming Experimental plant.

Vent gas production is estimated at 490 m^3/d initially increasing to about 1180 m^3/d after several years of operation. Vent gas compression and recovery is not economically justified at this low level of production. The discharge to atmosphere will have insignificant environmental impact.

Only sweet natural gas will be utilized as fuel in the new steam generator at Leming and there will, therefore, be no increase in the emission of SO_2. The calculated ground level concentration (1 hr. avg.) of NO_2 will increase from a total of 0.182 ppm for the existing Leming steam generators to 0.198 ppm including the new steam generator at full load. About 3/5 of the new generator capacity is required to supply the horizontal well pilot. The above estimates of ground level concentrations compare to the standard of 0.21 ppm (1 hr. avg.)

II. Waste Waters

Produced water will be recovered and treated either in the Leming Plant or CLPP I and II water reuse plants and recycled for steam generation. In the event that recycle plant capacity is not available, the produced water will be injected into disposal wells.

Storm waters from the well pads will be retained by dikes around the perimeter of the pads and discharged after inspection to the surrounding drainage.

III. Fresh Water Source

Fresh make-up water will be supplied from Cold Lake and Ethel Lake within existing licences totalling 7.2 x $10^6/m^3$/year. The incremental fresh water required (difference between steam injected and water production) will be in the order of 100-200 m^3/d or 36,500-73,000 m^3/year.

IV. Oily Waste Management

Oily waste resulting from the HWP II will be handled by the same methods and in the same facilities as the materials from Leming and the CLPP projects. The volume generated will be small and will consist of incremental volumes of oily sands from wellhead clean-up and oily debris from clean-up of potential spills. These minor volumes will be disposed of together with materials from the existing operations by road application and/or land farming. A prototype incinerator is also being obtained in 1984 and will be evaluated as a potential disposal option.

V. Spill Contingency Plans

Contingency planning for this new pilot will be integrated with plans already in place for the Leming Plant and being expanded to cover the CLPP projects.

An on-site training course has been developed specifically for all appropriate Esso Resources Cold Lake operations personnel. In addition, supervisory personnel are being trained through the PITS On-Scene-Commanders course.

Esso is also an active member of the Lakeland Environmental Protection Association. This organization was founded in the fall of 1982 under the direction of the Canadian Petroleum Association Oil Industry Spill Cooperative Program. The primary objective of the cooperative is to establish a regional spill response capability. Equipment has been purchased and stored in a trailer for rapid movement to a spill location. Equipment includes portable tank storage, pumps, spill containment boom, skimmers, hoses, and safety equipment.

VI. Surface Disturbance

Various techniques being applied at Leming and CLPP to minimize surface disturbance will also be incorporated into the HWP II planning and construction. These techniques include directional drilling and utilization of common rights-of-way.

Interim revegetation and other measures will be implemented as appropriate to control erosion. Final reclamation, similar in concept to that described in the D&R plans for Phases I to IV, will be affected after project abandonment.

10. PRODUCTION ACCOUNTING

Monthly oil production from the HWP II will be metered as shown in the process flow diagram (Figure 5.2) and reported similarly to other Leming wells.

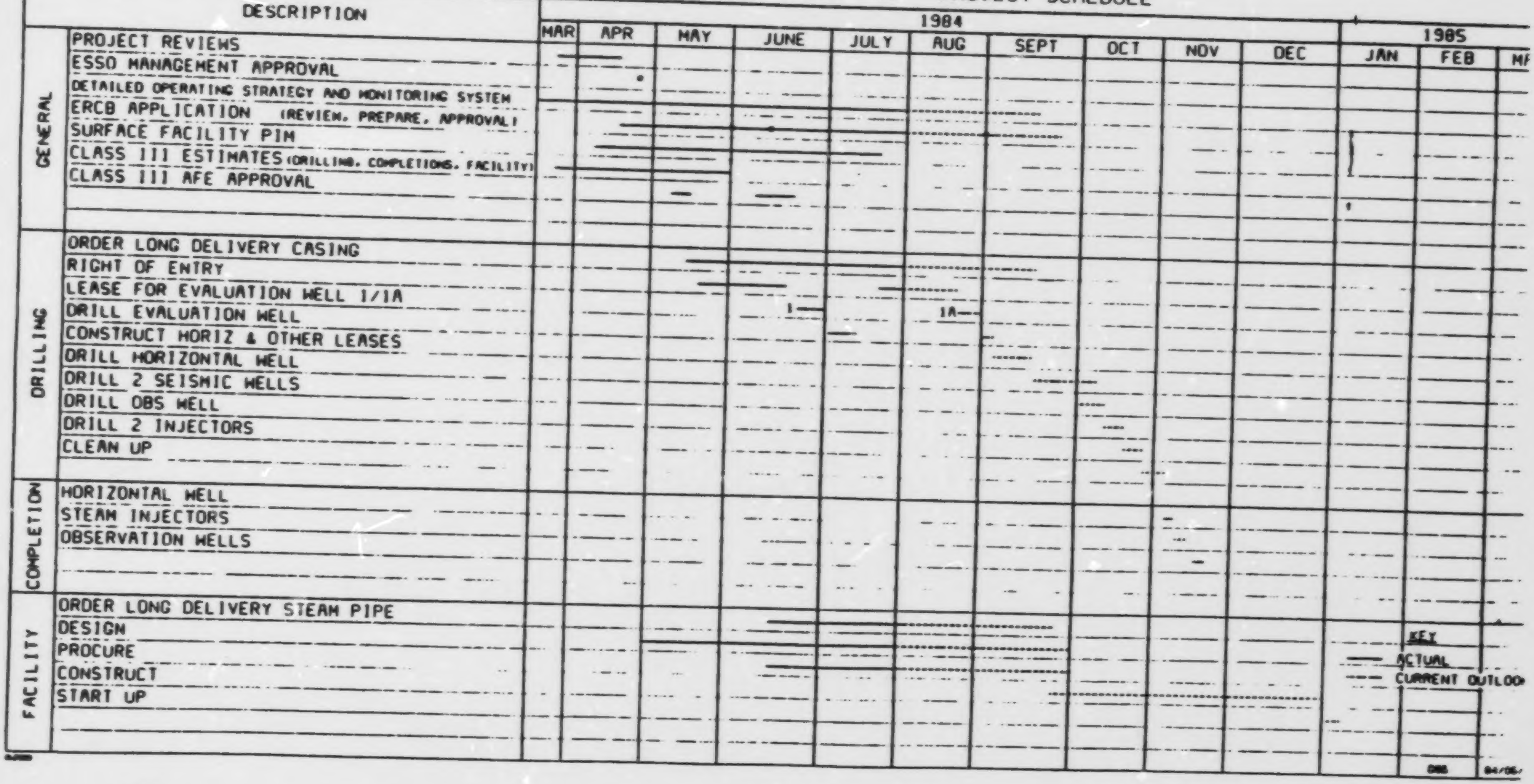
11. PROJECT SCHEDULE

Pending regulatory approvals, drilling of the horizontal well and the support wells is planned for mid-September and steam injection slated to start in January, 1985 (see Project Schedule - Figure 11.1).

An evaluation well will be drilled in late August/early September, 1984 to ensure that Section 6 is a suitable reservoir for this new pilot (i.e., no gas cap or excessive bottom water condition).

FIGURE 11.1

COLD LAKE HORIZONTAL WELL PILOT II - PROJECT SCHEDULE



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(2) R.M. Butler, G.S. McNab, H.Y. Lo - Theoretical Studies on the Gravity Drainage of Heavy Oil During In-Situ Heating, Canadian Journal Chemical Engineering, Volume 59 (4), pp 455-460, 1981.

(3) R.M. Butler, D.J. Stephens - The Gravity Drainage of Steam-Heated Heavy Oil to Parallel Horizontal Wells, Journal Canadian Petroleum Technology, Volume 20 (2), pp 90-96, 1981.

(4) R.M. Butler, D.J. Stephens, M. Weiss - The Vertical Growth of Steam Chambers in the In-Situ Thermal Recovery of Heavy Oils, Proc. 30th Canadian Chemical Engineering Conference, Edmonton, Alberta, Volume 4, pp 1152-1167, 1980.

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(6) P.J. Griffin, P.N. Trofimenkoff - Laboratory Studies of the Steam-Assisted Gravity Drainage Process, Fifth Annual 'Advance in Petroleum Recovery & Upgrading Conference', 1984.

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Drilling the Cold Lake Horizontal Well Pilot No. 2

by R.R. MacDonald, *Esso Resources Canada Ltd.*

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ABSTRACT

Esso Resources Canada Limited has completed its second horizontal well at Cold Lake, Alberta, Canada. The first horizontal well, a steam stimulated heavy oil pilot, has been an excellent producer. Based on this performance, a 1000 meter horizontal interval well was conceived. Spudded from vertical, the well achieved a 1016 meter horizontal interval with a total horizontal displacement of 1500 meters. The horizontal interval is at a true vertical depth of 468 to 475 meters.

Drilling the long horizontal well in shallow, unconsolidated formations was performed with a conventional drilling rig, however, unconventional drilling techniques were used. As an example, drill pipe was run with high compressive loads while drilling, and 1-1/2 degree bent housing motors were alternately rotated and oriented to maintain the course of the well. The details of the well design, the drilling techniques used and the problems encountered are discussed.

INTRODUCTION

Bezaire and Markiw (1979) described Esso Resources first horizontal well drilled at Cold Lake Alberta Canada, HWP #1. This was followed by its second at Norman Wells in the Northwest Territories in 1979, 43X. Figure #1 compares the horizontal intervals in these wells.

The application of horizontal wells to the heavy oil deposits at Cold lake relies on drainage to the horizontal well stimulated by steam injectors above the horizontal section. The production rate is expected to be proportional to the length of the wellbore open to the reservoir.

The first horizontal well, with a single injector, has been an excellent producer. Based on this performance, a 1000 meter long horizontal interval well pilot project was conceived with three objectives in mind:

- o to test the drillability of a long horizontal well,
- o to evaluate downhole pump alternatives capable of high continuous production rates,
- o to test the feasibility of multiple injector wells.

WELL DESIGN

The desire to evaluate alternate well pumping equipment required large intermediate casing. A 340 mm casing was selected to provide that evaluation flexibility. This choice however, resulted in a large uphole well design and a comparably large drilling rig to run that equipment. Figure 2 shows 150 meters of 508 mm surface casing being run to cover glacial till. On the previous pilot, significant problem time was experienced in this portion of the hole, so to avoid that same difficulty, surface casing was run.

References and illustrations at end of paper.

The 340 mm intermediate casing was designed to reach the 90° point to maximize the production from the drainage of the reservoir. This casing was designed for thermal loading and included:

- L80 seamless pipe and coupling material,
- oversized buttress couplings
- thermally designed thread dope
- torque turned couplings
- casing cemented full length with Class "G" cement plus 40% silica flour.

Below the 340 mm casing, a 194 mm slotted liner was selected. This diameter was chosen to allow the option of running a 140 mm liner should the 194 mm liner not reach a minimum desired length. The slotted liner is not cemented.

To accomodate potential thermal expansion and to limit sand production around the top of the liner, a special drag block pack-off was designed to provide a liner to intermediate casing seal. A hanger was not used nor was a pressure seal required.

DRILLING EQUIPMENT

Drilling Rig

Although the well had a planned measured depth of 1717 meters, the rig selected had a depth capacity rating of 4575 meters. This rig had equipment with the capacities determined necessary to drill the long horizontal well. The following is equipment and the reasons for its requirement for this well.

127 mm drill pipe. Drag modelling suggested 127 mm drill pipe would be needed to withstand the compressive loading during drilling. A rig with 127 mm drillpipe and the ability to rack that pipe was necessary.

Racking Area. The set back area associated with the deep rig conveniently accommodated 300 meters of 171 mm collars and 450 meters of 127 m heavy weight drill pipe.

699 mm Rotary Table. Surface hole would be opened to 660 mm with 508 mm casing being run.

2-1100 Horse Power Mud Pumps - Drilling 457 mm directional hole and opening surface hole to 660 mm would require high volumes to clean the hole. Additionally, in the highly deviated well, the removal of the cuttings bed could require higher than normal circulation rates. These pumps would allow us the freedom to use this approach if necessary.

DESIGNING FOR DRAG

In a shallow horizontal well, pick-up drag is not the main limitation to drilling or casing the well. Rather slack-off is the hurdle.

Pipe must be pushed into the well, to first get the pipe to bottom and secondly to get weight on bit. The process used to design a drill string or casing running string is as follows:

Step 1: Select an effective coefficient of friction.

Ideally, frictional data from previously drilled wells of a similar design and similar formations would be used. In the case of this well, data was not available for a long horizontal interval in unconsolidated formations. Consequently, a design factor had to be selected.

Johancsik et al (1983) observed, through field measurement and computer modelling, the effective coefficient of friction ranging from 0.2 to 0.4 with water base mud. Because of the unconsolidated formations at Cold Lake, 0.35 was selected for drilling and 0.4 for running casing.

Step 2: Select Drill String to overcome Drag

Using the Exxon drill string force calculation program (FORCAL), tension/compression, side load and torque can be predicted for segments of the drill string. In this extreme application of highly deviated wells, the sections of the drill string nearest the bottom of the hole must be kept to a minimum if a 1000 meter horizontal interval is expected to be achieved. Aluminum drill pipe comes to mind but the next design step restricts its use.

Step 3: Check Drill String Components for Potential Buckling

In a shallow horizontal well, drag loading can expose the lighter drill string components to compressive loads in excess of their buckling capability. To avoid this occurance, charts developed by Dawson and Paslay (1982) were used to check for the onset of buckling.

An interactive process results, cycling back to step 2 or step 1. Optimization of the drill string component and drilling fluid selection is accomplished without consideration of economic or other external factors. Building these restrictions into the analysis achieves the final design.

The design chosen for the HWP #2 consisted of 127 mm, 29 kg/m Grade E drill pipe along the horizontal followed by 450 meters of 127 mm heavy weight drill pipe and 300 meters of 171 mm drill collars to surface (Figure #3). The drag expected along the horizontal dictated that the 127 mm steel drill pipe be used which in turn necessitated the higher strength heavy weight pipe above. Table 1 compares pipe buckling strengths to the predicted load.

The same basic design is used to run the liner replacing the 127 mm drill pipe with the 194 mm slotted casing. An additional consideration was the need to circulate the casing. A cuttings bed was expected therefore a tubing circulating string was planned for. The additional drag that would be imposed was included in the liner running design.

Directional Accuracy

Directional accuracy was a major design concern for the well. Two key questions required answering to select an appropriate drilling technique:

1. What is the expected directional survey accuracy for this well?
2. What control should be expected from the drilling assemblies?

Survey Accuracy

Accurate well bore positioning is critical for steam stimulated drainage to establish early communication between injectors and the horizontal well and secondly to maximize recoverable reserves by drilling at an optimum true vertical depth along the horizontal. Johancsik et al (1984) discuss the application of MWD to the highly Deviated Drilling at Norman Wells. With this experience, MWD was analysed for its use at Cold Lake.

To predict the accuracy, a commercially available computer program was used to model the MWD instrument in this application. The program accounts for drill string magnetization, bias and scale error.

In this application, the MWD instrument would not be rotated in the build section but would be rotated along the horizontal. The model predicted one standard deviation error of 4.0 meters in the vertical plane and 45 meters in the horizontal at total measured depth. At the end of the build up section, these errors would be 1.5 and 20 meters for vertical and lateral position respectively.

The vertical error was within normal directional assembly capability, however one improvement could be made. Since the top of the production zone, the Clearwater formation, is accurately known from correlation wells, a check on survey depth could be made using a through drill pipe gamma ray log. The log would ensure that no gross errors were made in vertical depth, however the expected error at the Clearwater top was 1.2 meters. Therefore the potential improvement was limited if the MWD instrument worked as well or better than modelled.

The lateral error was unacceptable if the injectors were to be drilled within 3 meters of the horizontal well. This proximity was necessary to establish early communication between the wells. A rate integrating gyro was considered to be run in the intermediate casing to reduce the error at the start of the horizontal interval to 1.5 meters. Since the horizontal interval would only be surveyed by MWD, the error at the end of the well would only be reduced to 31 meters. An alternate technique was required.

Seismic Proximity Location Technique

Following the drilling of the horizontal well, a seismic technique was used to determine its position. The technique consisted of running 8 hydrophones spaced 15 meters apart into a vertical evaluation well expected to be 20.5 meters from the horizontal well. Primacord charges detonated in the horizontal well would be detected by the string in the vertical well to pinpoint the horizontal well location. The technique was estimated to have one standard deviation accuracy of 2.5 meters.

With the horizontal well position corrected, the vertical injectors could be drilled using conventional directional techniques to achieve an acceptable injector to horizontal well proximity.

Drilling Assembly Performance

Our directional drilling experience at Cold Lake and Norman Wells guided us to the use of padded 1 1/2 degree bent housing motors to drill the build section of the hole. This assembly has proven to give consistent performance in soft unconsolidated formation.

By varying the thickness of the pad, the rate of build the assembly will provide can be altered. The planned build rate was 4 degrees/30 meters drilling 457 mm hole with a 244 mm bent housing motor. A 60 mm pad was welded to the motor at the bottom side of the bend.

To drill the horizontal portion of the well, non-bent assemblies were planned. To minimize bit walk, straight motors on a stabilized rotary string would be rotated. By altering the position and diameter of rotating and non-rotating stabilizers, control of wellbore trajectory was hoped to be achieved. Bent asemblies were to be avoided to minimize the potential for doglegs.

Soft mill tooth bits were being used successfully in the Cold Lake production project and, therefore, the same was planned for the horizontal well.

A summary of the drilling program as planned is included in Table 2.

THE HORIZONTAL WELL AS DRILLED

Drilling Time Analysis

The horizontal well required 37.8 days to drill of which 29.6% was problem time. Table 3 shows the distribution of that time for the various drilling activities. Drilling another well of this design at Cold Lake should be accomplished in less than 25 days. Given optimization of the well design and the drilling technique, a 10 to 15 day well is not unreasonable.

Conventional drilling techniques would account for a portion of that improvement but the majority would be realized from three key non-conventional areas: drag limitations, directional assembly performance, and directional survey accuracy.

Drag Limitations

The drag observed in this well was in excess of that predicted; consequently, tripping in and running casing was hampered by insufficient running weight. The blocks were used to assist the drill pipe and heavy weight pipe into the hole until sufficient weight above the string was achieved with heavy weight and drill collars. After 750 meters along the horizontal, tripping in slowed, accounting for 23% of the total problem time on the well.

In running the liner, as was done in the drill string, heavy weight drill pipe was to be followed by the drill collars. The high drag necessitated running 2 stands of collars immediately after the liner. Heavy weight drill pipe was then run but after 6 stands, collars again had to be run. The switching from collars to heavy weight was repeated 3 times and was ultimately limited by the 330 meters of collars on site. Table 4 compares the coeffients of drag to the design factors.

Even with this drag, the well was drilled to a total measured depth of 1773 meters with a total horizontal displacement of 1500 meters. The horizontal interval beyond the intermediate casing string was 1016 meters long of which 900 meters was covered by the liner.

Two alternatives that could be considered to improve the running times would be to use a top drive with pull down capability and to increase the weight of the running string. The increased load would, however, have to be balanced with the buckling limits of the pipe.

Directional Assembly Performance

In the build section of the hole, two directional problems were encountered with the 244.5 mm bent housing motor. At low inclination, less than 20 degrees, the bent housing did not build at the design rate. A 1 1/2 degree kick sub above the motor overcame this limitation.

The second problem was excessive build rate after 45 degrees. Rate variation was to be obtained by varying the pad thickness; however, an intermediate step was used. The bent housing was rotated and had excellent hold characteristics. To obtain an intermediate build rate, the assembly would be drilled oriented for a portion of a single and rotated for the remainder. This downhole flexibility gives one the freedom normally only available with more complicated downhole equipment.

The same process was used along the horizontal when the straight stabilized assemblies proved to be inconsistent. One plug back in the horizontal resulted before the decision was made to rotate in that portion of the hole.

Directional Survey Accuracy

The two checks on the survey accuracy, the through drill pipe gamma ray log and seismic proximity evaluation confirmed the expected accuracy of the inclinometers. Differences of less than 1 meter in the vertical plan were observed in both of those checks. The vertical range along the horizontal was limited to a 5 meter band for all but the last 20 meters of the well where it dropped 2 meters below that band (Figure 4).

On the azimuth, the seismic technique positioned the horizontal well 11.7 meters from the observation well with the resultant correction being 8.8 meters closer to the obervation well than surveyed (Figure 5). From this one point correction, the wellbore as assumed to be parallel to the surveyed path. From this corrected path, the injector locations were identified and drilled vertically to be within 3 meters of the horizontal well in the horizontal plane. In addition to the injectors, three observation wells were drilled surrounding the first injector.

Future Horizontal Well Technology

The benefit of using horizontal wells in low dip reservoirs, where gravity drainage is the key production mechanism, could be dependent on the ability to accurately control the wellbore trajectory. Should intersection (close proximity) wells be drilled in conjunction with the horizontal well, alternate techniques could be used to reduce this distance. In both cases, reservoir performance may be enhanced with refinements to directional control.

Development of equipment and techniques to drill the wells with sufficient accuracy could be the key limitation to achieving peak production levels. Evaluation of this pilot well production performance will direct future Cold Lake horizontal well drilling activity.

ACKNOWLEDGEMENT

The author thanks Esso Resources Canada Limited for permission to publish this paper.

Special recognition is extended to Herb Heller, the Drilling Supervisor who's diligent effort made the well a reality and Doug Gust for his analysis of survey accuracy and his on-site surveillance.

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TABLE 1

FORCAL PREDICTED COMPRESSIVE LOADS VERSUS BUCKLING LIMITS

DRILL STRING COMPONENT	DEPTH (Meters)	HOLE ANGLE (Degrees)	COMPRESSION LOAD (daN)	BUCKLING LIMIT (daN)
127 mm Heavy Weight Drill Pipe	275 480 712	31 59 90	15,000 17,880 13,800	16,000 20,700 22,200
127 mm Drill Pipe	712 1,212	90 90	13,800 9,200	13,300 13,300

Design Coefficient of Friction = 0.35 (Forcal)
Mud Density = 1,100 kg/m^3
Force on Bit = 2,200 daN
Drilling Hook Load = 14,600 daN
Total Measured Depth = 1,712 meters

TABLE 2

PLANNED HORIZONTAL WELL DRILLING PROGRAM

SURFACE HOLE

- Drill 457 mm hole to 40 meters measured depth (m MD)
- Kick off with 457 mm bit and 244 mm, 1 1/2° bent housing motor
- Drill to 150 m MD and 15° inclination
- Open the hole to 660 mm
- Run and cement 508 mm casing
- Head up with 508 mm diverter

INTERMEDIATE HOLE

- Drill out with 457 mm rotary string
- Directionally drill to Clearwater formation top with 457 mm bit and 244 mm, 1 1/2° bent housing motor
- Check MWD accuracy with through drill pipe gamma-ray log
- Drill 457 mm hole to 90° inclination
- Run and cement 340 mm thermal design casing

PRODUCTION HOLE

- Drill out with 308 mm bit and rotary string
- Drill 251 mm hole along the horizontal with 165 mm straight motor and non-bent assembly
- Run 194 mm slotted liner
- Cut off top of liner leaving 5 meter overlap

COMPLETION

- Install liner top packoff
- Head up with 340 mm tubing spool
- Run tubing to 550 meters

TABLE 3

DRILLING TIME ANALYSIS

ACTIVITY	ACTIVITY DURATION (DAYS)	PROBLEM TIME (% OF TOTAL)
Drilling	5.2	1.6
Tripping	10.9	23.5
Rig Maintenance and Repairs	1.8	12.2
Directional Surveying	3.0	4.0
Conditioning Mud and Hole	2.6	17.1
Working Pipe and Fishing	0.4	4.2
Casing	3.7	7.2
Waiting on Cement	2.0	5.9
Heading up and Drilling out	2.9	0.3
Run Side Track Plugs (2)	1.6	14.2
Completion	2.4	9.0
Miscellaneous	1.3	0.8
TOTAL	37.8	100.0
	-	(11.2 Days, 29.6% of Total)

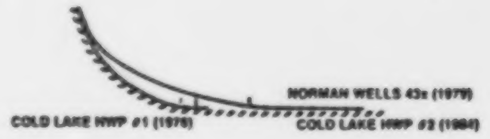
TABLE 4

COEFFICIENTS OF DRAG (FORCAL)

HWP #2 – DRILL STRING AT TD	0.43
– LINER AT TD	0.44
– 950 METRES OF LINER	0.51
COMPARISONS	
– OIL BASE MUD	0.20 – 0.25
– HWP #1	0.23
– WATER BASE MUD	0.30 – 0.35
HWP #2 – DESIGN	0.35 – 0.40

FIGURE 1

ESSO HORIZONTAL WELLS


NORMAN WELLS 43x (1979)
COLD LAKE HWP #1 (1978)
COLD LAKE HWP #2 (1984)

	HORIZONTAL INTERVAL – m
—— HWP #1	77
—— 43x	563
----- HWP #2 (DESIGN)	1000

FIGURE 2

COLD LAKE HORIZONTAL WELL PILOT #2 WELL DESIGN

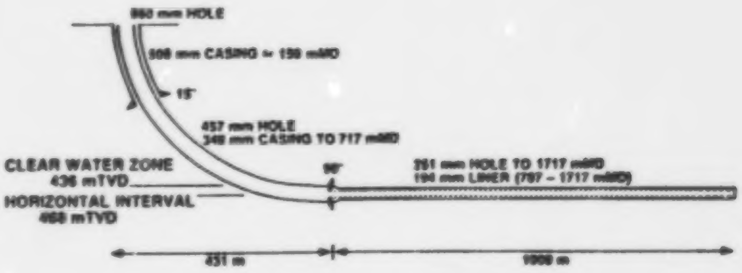

660 mm HOLE
508 mm CASING ~ 150 mMD
15°
457 mm HOLE
340 mm CASING TO 717 mMD
CLEAR WATER ZONE
436 mTVD
HORIZONTAL INTERVAL
468 mTVD
90°
251 mm HOLE TO 1717 mMD
194 mm LINER (707 – 1717 mMD)
431 m
1000 m

FIGURE 3

DRILLING/LINER RUNNING
DRILLSTRING DESIGN

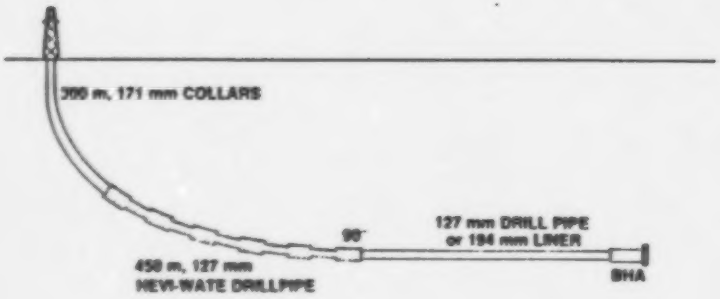

300 m, 171 mm COLLARS
90°
127 mm DRILL PIPE
or 194 mm LINER
450 m, 127 mm
HEVI-WATE DRILLPIPE
BHA

FIGURE 4

VERTICAL PROJECTION
ACTUAL vs DESIGN

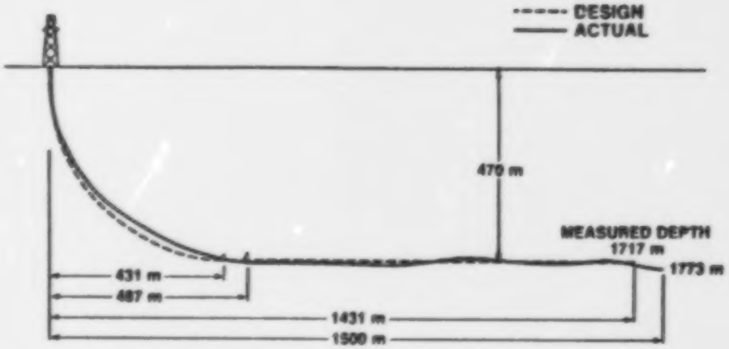
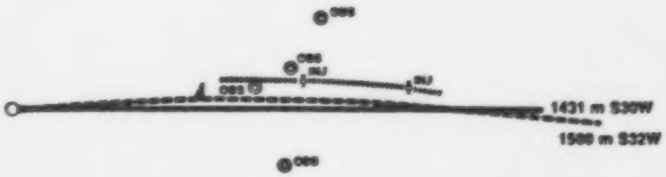

DESIGN
ACTUAL
470 m
MEASURED DEPTH
1717 m
1773 m
431 m
487 m
1431 m
1500 m

FIGURE 5

HORIZONTAL PROJECTION
ACTUAL vs DESIGN
SEISMIC CORRECTION


OBS
OBS
SIJ
SIJ
OBS
1431 m S30W
1500 m S32W
OBS

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Bechtel develops innovative method for horizontal drilling

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Scientific Software-Intercomp
Houston

Horizontal wells were first drilled over 40 years ago. Downhole drilling problems and the lack of economic incentives prevented their widespread use.

There is now a renewed interest, especially in heavy-oil recovery, due to relatively recent improvements in directional drilling and the incentives to add reserves.

The horizontal drilling process used by Bechtel differs from conventional drilling in the following areas:

- Horizontal holes are drilled from vertical wells and require a turning radius of only 12 in.
- As many as 24 horizontal holes may be installed in any particular horizontal plane.
- The method of drilling involves hydraulic jetting with drilling rates varying from 10 to 100 fpm.
- The drilling process is more economical than conventional horizontal drilling methods. Actual rig time required for installing four horizontal holes in shallow unconsolidated formations is normally less than 60 hr.

Horizontal drilling. Difficulties in control of deviation, drilling problems associated with the effect of gravity while drilling horizontally, and the low price of crude oil, have all contributed to a lack of substantial development and utilization.

Thanks to recent substantial improvements in horizontal drilling, interest in production from horizontal boreholes has been revived in recent years. ARCO, Elf, Texaco, and Esso, among others, have participated in significant applications. The U.S.S.R. is presently expanding its horizontal heavy-oil facilities at Yarega from 9,000 b/d to 30,000 b/d.

Development of the Bechtel horizontal drilling process (HDP) was initiated approximately 4 years ago. The system is proprietary, and a number of patents have been allowed.

As a part of field testing, Bechtel Investments Inc. (BII) has installed approximately 350 horizontal holes in numerous formations both for developmental engineering and commercial applications.

The drilling technology has thus far been employed in improving heavy oil recovery under steam stimulation in California. Several pilots are underway. The design of these pilots was aided by extensive reservoir simulation work.

A schematic showing the general properties of the system is provided in Fig. 1

Bechtel's project has five technical and economic objectives:

- Provide multiple, horizontal radials of 100-200 ft long from a single well in 500-3,000 ft deep unconsolidated heavy oil reservoirs.
- Drill a 4-in. diameter 100-200 ft horizontal hole rapidly through an unconsolidated formation.
- Log the individual radial for bottomhole geometry.
- Perforate and gravel pack for sand control, if required.
- Provide the whole process at an economic cost.

Downhole tools. To effectively penetrate shallow or thin reserves, the system incorporates an erectible whipstock which allows the drill-

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[*] Now with Sohio, Dallas

Fig. 1

Horizontal-drilling system

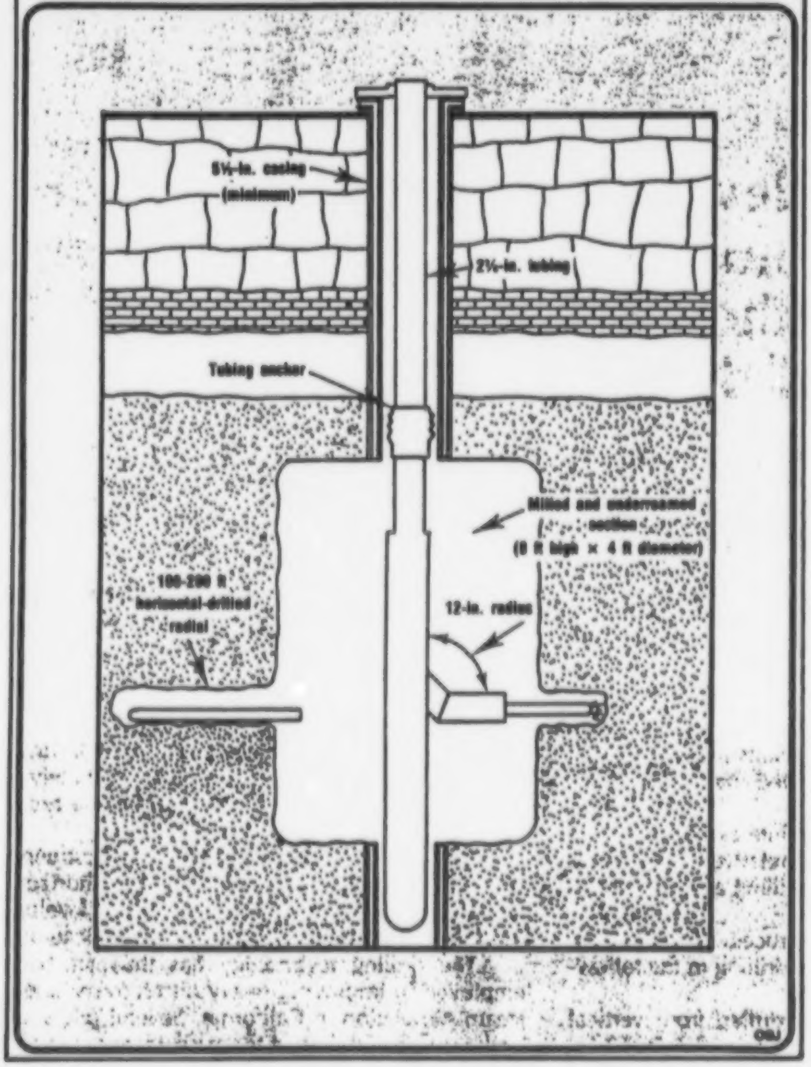

5½-in. casing (minimum)
2⅞-in. tubing
Tubing anchor
Milled and underreamed section (8 ft high × 4 ft diameter)
100-200 ft horizontal-drilled radial
12-in. radius
OGJ

Fig. 2

Matching test well, simulation

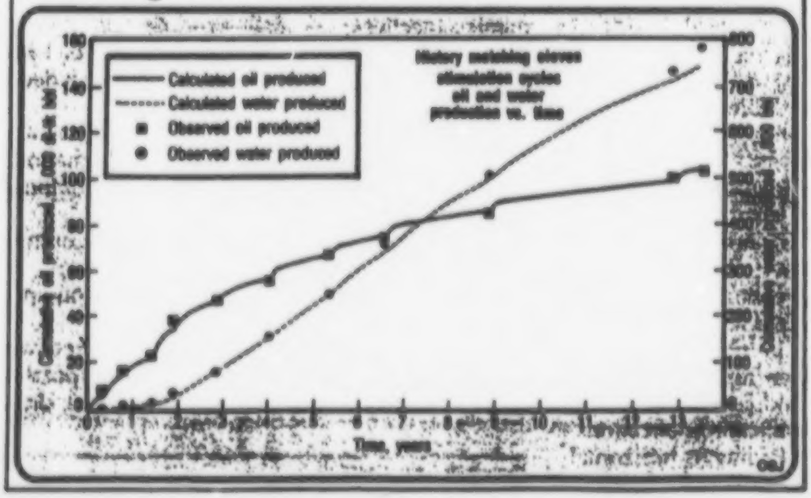


Table 1

Reservoir properties

Layer	Permeability, md	Thickness, ft	Oil saturation %
1	2,500	20	60
2	3,500	20	58
3	4,000	15	55
4	3,000	15	53
5	3,000	15	51
6	3,000	15	48

Table 2.

Kern River generic data

Initial reservoir conditions:		
Temperature	90° F.	
Pressure	60 psi	
Gas saturation	0	
Net to gross ratio	0.7	
Pore volume compressibility	735 E-6 1/psi	
Oil Properties:		
Gravity	14° API	
Distillation effects	None	
Viscosity	1,070 cp at 90° F.	
Viscosity	4 cp at 350° F.	
Temperature-dependent relative permeability end-points:	@ 90° F.	@ 400° F.
Irreducible water saturation, S_{wi}	0.37	0.50
Residual oil to water flood, S_{orw}	0.30	0.10
Residual oil to steamflood, S_{org}	0.10	0.06
Water relative permeability at S_{orw}	0.014	0.022
Oil relative permeability at S_{wi}	1.0	1.0
Steam relative permeability at S_{org}	0.51	0.51

string to make a tight radius (12 in.) turn. This tool is tubing-conveyed and run in the hole in its unerected position.

An approximate 8 ft by 4 ft underreamed chamber is required; section-milling and conventional hole-opening are followed by application of a hydraulic undereamer developed to provide the required 4-ft diameter chamber.

After positioning in the previously underreamed section of the wellbore, the tool is erected by hydraulic pressure and oriented, as required, by a gyroscope. This whipstock is constructed to enable the drillstring to move from the vertical wellbore, around the 90° turn, through the straightening section, and out horizontally into the formation.

Drilling operations. The drillstring consists of 1.25 in. OD × 1.09-in. ID coiled tubing with a specially designed drillhead affixed. This drillhead consists of a series of circular nozzles which cut about a 4-6 in. hole, de-

Fig. 3

Extending simulation to radials

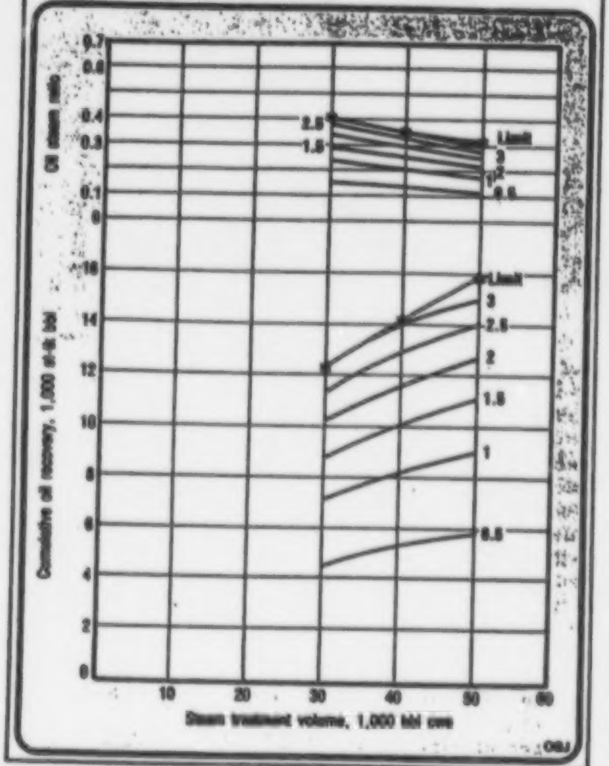
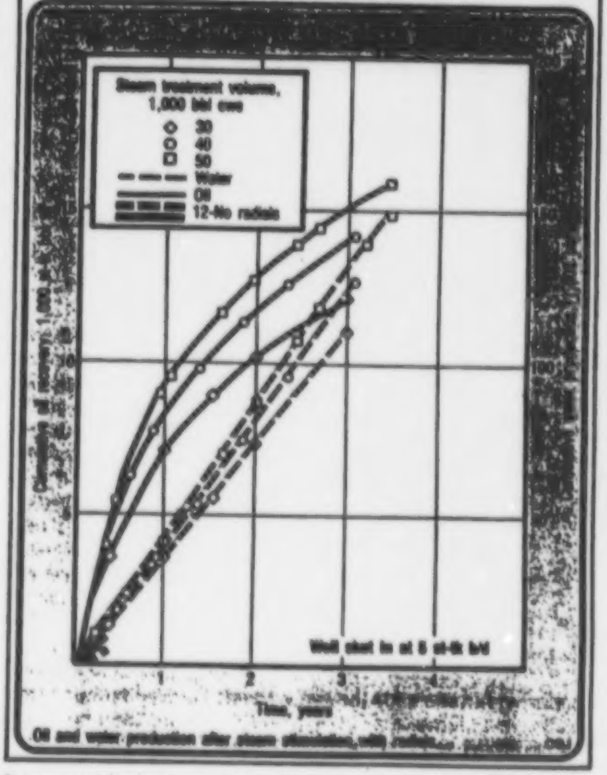


Fig. 4

Simulation with radials



Oil and water production after steam stimulation with radials

pending on formation type and depth.

The HDP utilizes the hydraulic jetting concept and requires surface pressures of 6,000-10,000 psig for water jet cutting. The drillhead does not rotate and can deliver in excess of 1,000 hp to the face of the formation.

Requirements for drilling additives, such as antiswell agents, can be readily accommodated.

The drillstring is propelled through the formation by internal fluid pressure. Average velocities range from 10-100 fpm.

In order to regulate the forward movement of the drillstring during drilling operations, a restraint mechanism is attached from the surface to the drillstring by means of a wireline latch. Tension is maintained, assuring the drillstring is always controlled from the surface.

Since the drillstring is under tension as it exits the whipstock, it has a natural tendency to maintain the initial drill face orientation as it moves out horizontally into the formation, thus greatly enhancing driectional control. During operations, pressure, flow and velocity are monitored to provide drilling control.

Logging. Conventional logging tools cannot be utilized in the HDP due to the tight turns involved, therefore, new directional logging equipment has been developed to provide bottomhole geometry. All electronics are packaged in a semiliquid plastic material with a supportive flexible sheath. These logging systems currently provide data accurate to ± 1° of vertical deviation. Azimuth tools are currently being tested.

Completion technique. Production practices in many areas of the southern San Joaquin Valley do not use gravel packing for sand control. Therefore, in normal operations, the drillstring is severed and lies along the bottom of the 4-in. hole.

Steam injection and oil production occur in this radial borehole as well as the vertical wellface.

Other forms of well completion have been investigated and tested whereby a consolidated gravel pack is placed and the drillstring perforated, thereby becoming the production tubing.

After logging the horizontal borehole, the drillstring/production tubing is electrochemically severed as it enteres the underreamed section of the vertical wellbore. If required, perforation of the production tubing can also be accomplished by utilizing flexible electrochemical tools which can be pumped down into the appropriate position(s) as required. Conventional slotted liners are commonly run over the underreamed section of the vertical wellbore.

Reservoir simulation work. To evaluate the performance of radials in steam stimulation of heavy oil reservoirs, a simulation study was conducted using typical Kern River data.

Table 1 shows permeabilities, porosities, and oil saturations for the generic reservoir model used in this study. Other pertinent data such as fluid properties and initial reservoir conditions are given in Table 2.

The simulated operating strategy is also typical of Kern River. Injection periods of 20 days, soak intervals of 7 to 10 days, and production periods of approximately 1 year were assumed.

A total of nine simulation runs were made, each involving three stimulation cycles. Two of the nine runs utilized conventional vertical wellbores and provide a basis for comparison. The other seven runs simulate two to four radials from 50 to 200 ft long.

These simulation runs also apply steam treatment volumes of 20,000 to 80,000 bbl condensed water equivalent (cwe) of steam per cycle. Table 3 summarizes the results of all nine simulation runs.

Comparison of cases 1V with 2H and 3V with 4H demonstrates the advantages of using injection and production radials as oil-steam ratio is

Reservoir simulation compares vertical, horizontal wellbores

[illegible]									
[illegible]	[illegible]	200	[illegible]	200	[illegible]	100	[illegible]	[illegible]	100
[illegible]	100	500	100	200	100	[illegible]	[illegible]	[illegible]	[illegible]
Injection rate specified [illegible]	1,000	1,000	2,000	1,000	1,000	1,000	1,000	1,000	1,000
Steam injection volume, [illegible] 1,000 bbl	160	160	120	120	[illegible]	[illegible]	240	[illegible]	240
Maximum injection pressure [illegible]	264	[illegible]	111	400	210	400	400	[illegible]	400
Oil produced [illegible] 1,000 [illegible] bbl	15.97	18.4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cumulative OSR [illegible]	0.265	0.307	0.255	0.240	0.290	0.326	[illegible]	[illegible]	[illegible]

Table 4

Test well reservoir properties

Layer	Thickness, ft	Permeability, md	Porosity, %
1	13	3,500	25.6
2	11	3,500	20.3
3	14	1,000	19.1
4	10	1,000	19.1
5	23	3,500	29.8
6	20	3,500	29.8
7	160	3,500	29.8

higher with radials for the same steam treatment volume.

Candidate well. The objective of the simulation study was to provide engineering guidelines for the design of a pilot well located in the Midway Sunset field. The study developed a respresentative model of the well and of the reservoir and then predicted reservoir performance during one additional stimulation cycle. Sensitivity to steam volume was the primary variable studied. The well model was equipped with four 100-ft horizontal boreholes (radials).

The well in question has been producing from Monarch sand, located in the Midway Sunset field, Kern County, Calif. The well has been steam stimulated 11 times in the Monarch and has produced approximately 100,000 st-tk bbl oil and 800,000 bbl water, as of April 30, 1984. Average oil production rate during April 1984 was 5 b/d. Cumulative steam injection was 98,500 bbl cwe.

Model validation. A seven-layer model with 14 grid blocks was used in matching the historical performance of the well. Table 4 shows the reservoir properties used in the model.

Fig. 2 shows the comparison between calculated and observed reservoir performance. Both oil and water production increased after the third stimulation cycle. This behavior could be attributed to the reported treatment which appears to have improved well productivity.

Prediction with radials. Having developed a representative model of the well by matching its 13-year performance, an additional stimulation cycle was simulated using four radials placed at 1,700 ft (middle of model layer 4), and with these assumptions.

The radials—consisting of 100 ft, 1.09-in. ID, unperforated pipe—will remain lying at the bottom of a 4-in. ID horizontal hole after placement.

Steam may enter the horizontal hole directly from the vertical wellbore, as well as from the end of the production tube.

Maximum steam volume available for treatment is 63,000 bbl cwe.

Surface injection facilities can accommodate a maximum injection rate of 2,500 b/d.

Wellhead steam quality and pressure are 80% and 850 psia.

Performance predictions with radials include four cases of varying steam treatment volume (10, 20, 30, and 50 thousand bbl cwe) in which steam injection is restricted to the interval 1,695 to 1,728 ft. An additional case involves injecting 30,000 b/d cwe of steam through the entire interval from 1,640 to 1,728 ft.

Fig. 3 compares oil and oil-steam ratio recovery as a function of steam-treatment volume. These results are provided at one-half-year increments up to the economic limit of 5 b/d.

In general, oil recovery increases with larger return treatment volumes. This increase, however, is at the expense of a reduction in oil-steam ratio.

Fig. 4 compares cumulative oil and water production for different steam treatment volumes. Also included in Fig. 4 are the results of a stimulation cycle at historical average steam volume without the use of radials. The radials provide substantial benefits.

Implementation. Based on the above simulation work, the subject well was equipped with four radials and treated with approximately 40,000 bbl cwe of steam. The well was allowed to soak for 16 days and put on production. The well actually produced approximately 700 bbl of crude during the sixth month of production (the most recent data available). The simulation work had projected approximately 600 bbl of crude to be produced during the same month.

The Bechtel horizontal drilling system meets the overall project technical and economic objectives.

Reservoir simulations indicate that the system can provide significant improvements in production from shallow unconsolidated heavy oil reser-

The authors ...

Pendleton

Ramesh

L.E. Pendleton is a senior petroleum engineer with Bechtel Investments Inc., Houston. Since 1983, he has been responsible for developmental engineering and marketing for Bechtel's horizontal-drilling services.

Prior to his present position, he participated in the engineering development of other proprietary drilling processes. Before moving to Houston, he worked for Bechtel in China, Alaska, and San Francisco. He received his technical education at Colorado School of Mines.

A.B. Ramesh is manager of reservoir engineering services at Sohio's Technology Center in Dallas. He was previously a senior consulting associate with Scientific Software-Intercomp in Houston. His principal areas of interest include application of thermal-recovery method to heavy and light oil reservoirs and treatment of volatile oil and condensate reservoirs.

He holds a BS degree from West Virginia University, an MS degree from Penn State, and a PhD from the University of Texas at Austin, all in petroleum engineering.

voirs. Initial pilot testing is encouraging. More production experience is necessary to prove the efficiency of the system.

Acknowledgment

The authors thank Wade and Wayne Dickinson, Petrolphysics Inc., San Francisco, Calif., who developed the system in conjunction with Bechtel, as well as the management at Bechtel Investments Inc., for permission to publish the data.

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BOOKS

The Resourceful Earth, *edited by Julian L. Simon and Herman Kahn. Published by Basil Blackwell Inc., 432 Park Avenue South, New York, N.Y., 10016. 593 pp.*

This book is a response to the Global 2000 report. It challenges the claims of that earlier work which forecast widespread environmental disaster by the turn of the century.

An independent team of world experts demonstrates in this book that on the basis of present trends, the world in 2000 will be less crowded, less polluted, more ecologically stable, and less vulnerable to resource-supply disruption than the world we know now.

Energy Policy in America Since 1945: A Study of Business-Government Relations, *by Richard H.K. Vietor. Published by Cambridge University Press, 32 East 57th St., New York, N.Y., 10022. 380 pp., $29.95.*

The author recounts the history of government intervention in U.S. energy markets since 1945. It is a saga, not of heroes and villains, says the publisher, but of ineffective institutions and administrative process.

Critical velocity examined for effects of erosion-corrosion

Bruce Craig
Mettallurgical Consultants Inc.
Denver

Recent interest in the accuracy of the erosion-velocity equation presented in API RP14E has led to a review of the factors that affect erosion in the oil industry with the intent of better quantifying these parameters.

The API equation is stated as:

$$V_e = \frac{C}{\sqrt{\rho}}$$

where ρ = fluid density, pound per cubic foot; C = a constant, typically 100 − 125; V_e = maximum allowable velocity, feet per second.

This equation is specifically given for calculating a limiting velocity for erosion; however, it has often been extended to calculation of a critical velocity for erosion-corrosion.

In this case, critical velocity is the velocity that would remove a corrosion inhibitor film from the pipe surface or even prevent film from forming. Critical velocity also can be that velocity that would strip a protective corrosion product film from the pipe wall. It is this latter point that will be addressed in this article.

Salama and Venkatesh[1] have discussed several approaches to critical velocity, depending on well conditions.

The first approach, and probably the most satisfying from an intuitive sense, is to use a fluid-mechanics equation relating velocity to shear stress at the pipe wall.

If the shear stress of the inhibitor or the corrosion product is set equal to the shear stress created by the fluid being transported, then a critical velocity should be obtained. In fact, the result is not realistic, based on field experience.

The equation:[2]

$$V_c = \sqrt{\frac{8g\tau}{f\rho}}$$

where:

g = Gravitational constant 32.2 fps/sec

f = Friction factor

τ = Shear strength of inhibitor or corrosion product to pipe wall, pounds per square foot.

V_c = Critical velocity, feet per second

reduces to approximately:

$$V_c = \frac{100{,}000}{\sqrt{\rho}}$$

when typical values for f (0.03) and τ (8,000 psi = 1,152,000 psf) are inserted. A value for f of 0.03 is more consistent with a scale-roughened surface than using f = 0.0015 for smooth pipe.

As evidenced by the large numerator, very few conditions in gas and oil wells would ever produce a critical velocity under these circumstances. Therefore, removal of a protective corrosion product by shearing action alone, apparently is not the primary means of erosion-corrosion in tubulars.

Salama and Venkatesh presented another equation they attributed to P. Griffith and E. Rabinowicx,[3] for erosion due to liquid impingement:

$$U = \frac{2Kv\rho^3V^6}{729g^3P^3\epsilon_c^4}$$

U = Wear volume rate, cu ft/sec

v = Impacting fluid volume rate, cu ft/sec

ρ = Fluid density, lb/cu ft

V = Impact velocity, fps

P = Target material hardness, psf

ϵ_c = Critical strain to failure

g = Gravitational constant, 32.2 fps/sec

K = High speed erosion coefficient, ~ 10^{-5}

By replacing v = AV where A is the cross-sectional area of the pipe and defining an erosion rate h = U/A the equation becomes:

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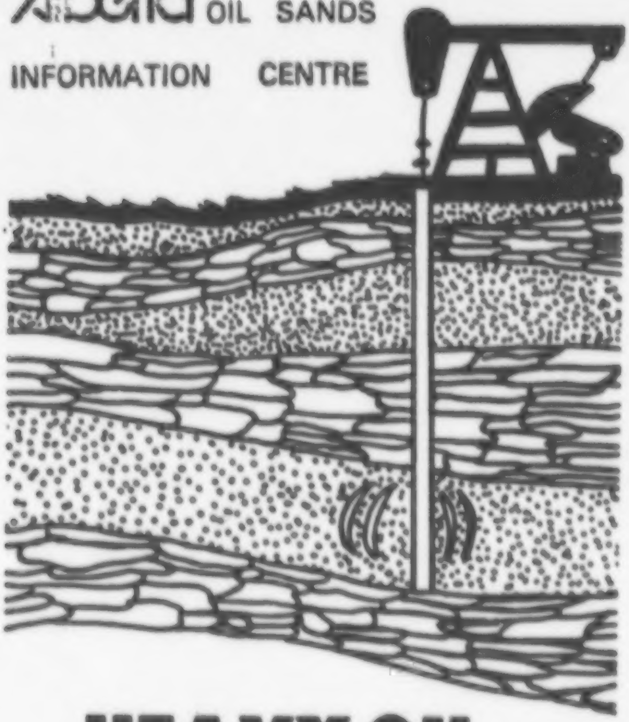

HEAVY OIL & OIL SANDS TECHNICAL SYMPOSIUM

"Challenges and Innovations 1985"

FEBRUARY 20, 1985

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AN INNOVATIVE METHOD OF DRILLING HORIZONTAL BOREHOLES

Presented By

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Scientific Software-Intercomp

February 20, 1985

ABSTRACT

Horizontal wells were first drilled over 40 years ago. Downhole drilling problems and the lack of economic incentives have prevented their widespread utilization. There is now a renewed interest, especially in heavy oil recovery, due to relatively recent improvements in directional drilling and the incentives to add reserves.

The horizontal drilling process utilized by Bechtel differs from conventional drilling in the following areas:

- Horizontal holes are drilled from vertical wells and require a turning radius of only 12 inches.
- As many as 24 horizontal holes may be installed in any particular horizontal plane.
- The method of drilling involves hydraulic jetting with drilling rates varying from 10 to 100 fpm.
- The drilling process is more economical than conventional horizontal drilling methods. Actual rig time required for installing four horizontal holes in shallow unconsolidated formations is normally less than 60 hours.

INTRODUCTION

Efforts to produce hydrocarbons through horizontal wells have been made for over 40 years. Difficulties in control of deviation, drilling problems associated with the effect of gravity while drilling horizontally, and the low price of crude oil have all contributed to a lack of substantial development and utilization.

Thanks to recent substantial improvements in horizontal drilling, interest in production from horizontal boreholes has been revived in recent years. ARCO, ELF, Texaco, and Esso, among others, have participated in significant applications. The U.S.S.R. is presently expanding its horizontal heavy oil facilities at Yarega from 9,000 b/d to 30,000 b/d.

Development of the Bechtel Horizontal Drilling Process (HDP) was initiated approximately four years ago. The system is proprietary, and a number of patents have been allowed.

As part of our field testing, BII has installed approximately 350 horizontal holes in numerous formations both for developmental engineering and commercial applications. The drilling technology has thus far been employed in improving heavy oil recovery under steam stimulation in California. Several pilots are underway. The design of these pilots was aided by extensive reservoir simulation work which will be covered later in the paper. A schematic showing the general properties of the system is provided in Figure 1.

PROJECT TECHNICAL AND ECONOMIC OBJECTIVES

A. Provide multiple, horizontal radials of 100 to 200 feet in length from a single well in 500 - 3000-foot-deep unconsolidated heavy oil reservoirs.

B. Drill a 100 - 200-foot horizontal hole rapidly, approximately 4 inches in diameter, through an unconsolidated formation.

C. Log the individual radial for bottomhole geometry.

F. Perforate and gravel pack for sand control, if required.

G. Provide the whole process at an economic cost.

DOWNHOLE TOOLS

To effectively penetrate shallow or thin reservoirs, the system incorporates an erectible whipstock which allows the drillstring to make a tight radius (12 inch) turn. This tool is tubing-conveyed and run in the hole in its un-erected position. An approximate 8 foot by 4 foot underreamed chamber is required; section-milling and conventional hole-opening are followed by application of a hydraulic underreamer developed to provide the required 4 foot diameter chamber. After positioning in the previously underreamed section of the wellbore, the tool is erected by hydraulic pressure and oriented, as required, by a gyroscope tool. This whipstock is constructed to enable the drillstring to move from the vertical wellbore, around the 90° turn, through the straightening section, and out horizontally into the formation.

DRILLING OPERATIONS

The drillstring consists of 1.25 inch O.D x 1.09-inch I.D. coiled tubing with a specially designed drillhead affixed. This drillhead consists of a series of circular nozzles which cut an approx. 4 inch - 6 inch hole, depending on formation type and depth. The HDP utilizes the hydraulic jetting concept and requires surface pressures of 6,000 - 10,000 psig for water jet cutting. The drillhead does not rotate and can deliver in excess of 1000 horsepower to the face of the formation. Requirements for drilling additives such as antiswell agents can be readily accommodated.

The drillstring is propelled through the formation by internal fluid pressure. Average velocities range from 10 - 100 fpm. In order to regulate the forward movement of the drillstring during drilling operations, a restraint mechanism is attached from the surface to the drillstring by means of a wireline latch. Tension is maintained assuring the drillstring is always controlled from the surface. Since the drillstring is under tension as it exits the whipstock, it has a natural tendency to maintain the initial drill face orientation as it moves out horizontally into the formation, thus greatly enhancing directional control. During drilling operations, pressure, flow and velocity are monitored to provide drilling control.

LOGGING

Conventional logging tools cannot be utilized in the HDP due to the tight turns involved, therefore, new directional logging equipment has been developed to provide bottomhole geometry. All electronics are packaged in a semiliquid plastic material with a supportive flexible sheath. These logging systems currently provide data accurate to ± 1° of vertical deviation. Azimuth tools are currently being tested.

COMPLETION TECHNIQUES

Production practices in many areas of the Southern San Joaquin Valley do not utilize gravelpacking for sand control. Therefore, in normal operations the drillstring is severed as described below and lies along the bottom of the approximately 4-inch-diameter hole which has been cut in the formation. Steam injection and oil production occur in this radial borehole as well as the vertical wellface. Other forms of well completion have been investigated and tested whereby a consolidated gravel pack is placed and the drillstring is perforated, thereby becoming the production tubing.

After logging the horizontal borehole the drillstring/production tubing is electrochemically severed as it enters the underreamed section of the vertical wellbore. If required, perforation of the production tubing can also be accomplished by utilizing flexible electrochemical tools which can be pumped down into the appropriate position(s) as required. Conventional slotted liners are commonly run over the underreamed section of the vertical wellbore.

RESERVOIR SIMULATION WORK

In order to evaluate the performance of radials in steam stimulation of heavy oil resevoirs, a simulation study was conducted using typical Kern River data. Table 1 shows permeabilities, porosities, and oil saturations for the generic reservoir model used in this study. Other pertinent data such as fluid properties and initial reservoir conditions are given in Table 2.

The simulated operating strategy is also typical of Kern River. Injection periods of twenty days, soak intervals of seven to ten days, and production periods of approximately one year were utilized.

A total of nine simulation runs were made, each involving three stimulation cycles. Two of the nine runs utilized conventional vertical wellbores and provide a basis for comparson. The other seven runs simulate two to four radials from 50 to 200 feet long. These simulation runs also utilize steam treatment volumes of 20,000 to 80,000 STB (CWE) of steam per cycle. Table 3 summarizes the results of all nine simulation runs. Comparison of cases 1V with 2H and 3V with 4H demonstrates the advantage of using injection and production radials as oil-steam ratio is higher with radials for the same steam treatment volume.

EVALUATION OF CANDIDATE WELL FOR TREATMENT WITH RADIALS

The objective of the simulation study was to provide engineering guidelines for the design of a pilot well located in the Midway Sunset field. The study (a) developed a representative model of the well and of the reservoir and (b) predicted reservoir performance during one additional stimulation cycle. Sensitivity to steam volume was the primary variable studied. The well model was equipped with four 100-foot-long horizontal boreholes (radials).

The well in question has been producing from the Monarch sand, located in the Midway Sunset Field, Kern County, California. The well has been steam stimulated eleven times in the Monarch and has produced approximately 100,000 STB oil and 800,000 STB water, as of April 30, 1984. Average oil production rate during April, 1984 was 5 STB/day. Cumulative steam injection was 98,500 (CWE).

RESERVOIR/WELL MODEL VALIDATION

A seven-layer model with fourteen grid blocks was used in matching the historical performance of the well. Table 4 shows the reservoir properties used in the model.

Figure 2 shows the comparison between calculated and observed reservoir performance. Both oil and water production increase after the third stimulation cycle. This behavior could be attributed to the reported treatment which appears to have improved well productivity.

PERFORMANCE PREDICTION WITH RADIALS

Having developed a representative model of the well by matching its thirteen-year performance, an additional stimulation cycle was simulated using four radials placed at 1,700 feet (middle of model layer 4). The assumptions were:

1. The radials — consisting of 100-foot-long, 1.09-inch ID, unperforated pipe — will remain lying at the bottom of a 4-inch ID horizontal hole after placement.

2. Steam may enter the horizontal hole directly from the vertical wellbore, as well as from the end of the production tube.

3. Maximum steam volume available for treatment is 63 MSTB (CWE).

4. Surface injection facilities can accommodate a maximum injection rate of 2,500 STB (CWE)/day.

5. Wellhead steam quality and pressure are 80% and 850 psia.

Performance predictions with radials include four cases of varying steam treatment volume (10, 20, 30, and 50 MSTB, CWE) in which steam injection is restricted to the interval 1695 to 1728 feet. An additional case involves injecting 30 MSTB (CWE) of steam through the entire interval from 1640 to 1728 feet.

Figure 3 compares oil and oil-steam ratio recovery as a function of steam treatment volume. These results are provided at one-half-year increments up to the economic limit of 5 STBO/D. In general, oil recovery increases with larger return treatment volumes. This increase, however, is at the expense of a reduction in oil-steam ratio.

Figure 4 compares cumulative oil and water production for different steam treatment volume. Also included in Figure 4 are the results of a stimulation cycle at historical average steam volume without the use of radials. Obviously from comparing the results radials provide substantial benefits.

IMPLEMENTATION

Based on the above simulation work the subject well was equipped with four radials and treated with approximately 40,000 STB (CWE) of steam. The well was allowed to soak for 16 days and put on production. The well actually produced approximately 800 barrels of crude during the sixth month of production (representing the most recent date available at the time of printing). The simulation work had projected approximately 600 barrels of crude to be produced during that same month.

CONCLUSIONS

The Bechtel horizontal drilling system meets the overall project technical and economic objectives set forth at the beginning of this paper. Reservoir simulations indicate that the Bechtel system can provide significant improvements in production from shallow unconsolidated heavy oil reservoirs. Initial pilot testing is encouraging. More production experience is necessary to prove the efficiency of the system.

ACKNOWLEDGEMENTS

To Wade and Wayne Dickinson; Petrolphysics, Inc., San Francisco, California, who developed the system in conjunction with Bechtel, as well as the management at Bechtel Investments, Inc., for permission to publish the data found herein.

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Table 1

STRATIFICATION
(10 x 5 x 6 RΘZ)

LAYER	PERMEABILITY (MD.)	THICKNESS (FT.)	OIL SATURATION (PERCENT)
1	2500	20	60
2	3500	20	58
3	4000	15	55
4	3000	15	53
5	3000	15	51
6	3000	15	48

Table 2

KERN RIVER GENERIC DATA

A. INITIAL RESERVOIR CONDITIONS:

TEMPERATURE	90 °F
PRESSURE	50 PSI
GAS SATURATION	0
NET TO GROSS RATIO	.7
PORE VOLUME COMPRESSIBILITY	735 E-6 1/PSI

B. OIL PROPERTIES:

GRAVITY	14 °API
DISTILLATION EFFECTS	NONE
VISCOSITY	1070 CP AT 90°F
VISCOSITY	4 CP AT 350°F

C. TEMPERATURE-DEPENDENT RELATIVE PERMEABILITY END-POINTS:

	@ 90°F	@ 400°F
IRREDUCIBLE WATER SATURATION (S_{wir})	.37	.50
RESIDUAL OIL TO WATER FLOOD (S_{orw})	.30	.10
RESIDUAL OIL TO STEAMFLOOD (S_{org})	.10	.06
WATER RELATIVE PERMEABILITY AT S_{orw}	.014	.022
OIL RELATIVE PERMEABILITY AT S_{wir}	1.0	1.0
STEAM RELATIVE PERMEABILITY AT S_{org}	.51	.51

Table 3

RESERVOIR SIMULATION SUMMARY
CYCLIC STEAM SIMULATION
COMPARISON OF VERTICAL & HORIZONTAL WELLBORES

CASE	1V	2H	3V	4H	5H	6H	7H	8H	9H
RADIALS: NUMBER-LENGTH	NONE	2-200'	NONE	2-200'	2-50'	2-100'	2-200'	4-50'	4-100'
TOTAL INTERVAL (VERTICAL & HORIZONTAL)	100	500	100	500	100	300	500	300	500
INJECTION RATE SPECIFIED (STB/DAY) CWE	1,000	1,000	2,000	2,000	4,000	4,000	4,000	4,000	4,000
STEAM INJECTION VOLUME FOR 3 CYCLES (MSTB-CWE)	60	60	120	120	207	235	240	221	240
MAXIMUM INJECTION PRESSURE	264	151	400	210	400	400	311	400	554
OIL PRODUCED IN 3 CYCLES (MSTB)	15.9	18.4	30.6	40.9	60.1	76.6	80.4	69.7	79.05
CUMULATIVE OSR	.265	.307	.255	.340	.290	.326	.335	.315	.33

Table 4

PILOT WELL EVALUATION
RESERVOIR PROPERTIES

LAYER	THICKNESS (FT)	PERMEABILITY (MD)	POROSITY (%)
1	13	3,500	25.6
2	11	3,500	20.3
3	14	1,000	19.1
4	10	1,000	19.1
5	23	3,500	29.8
6	20	3,500	29.8
7	160	3,500	29.8

Figure 1
SYSTEM SCHEMATIC

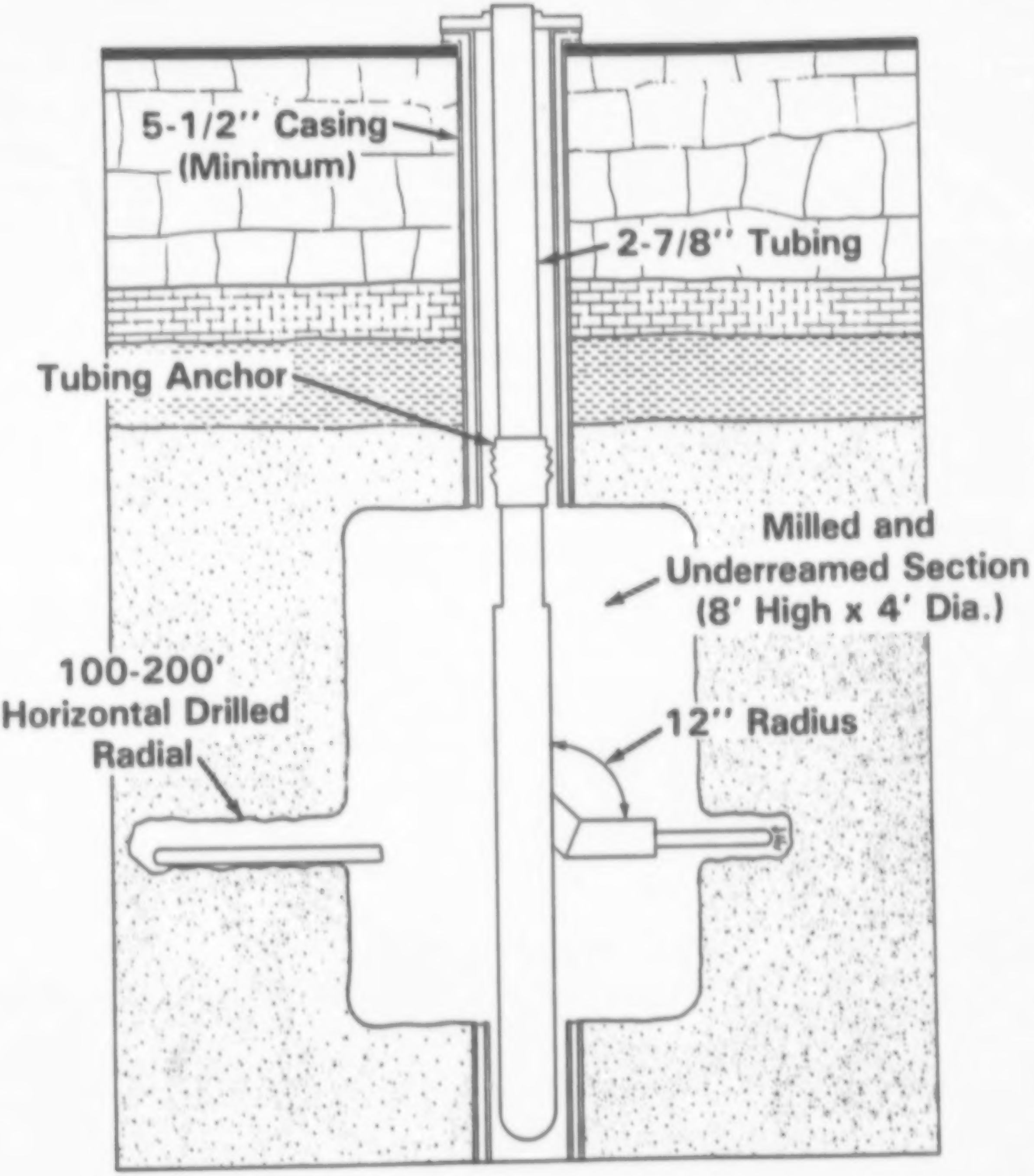

5-1/2" Casing
(Minimum)
2-7/8" Tubing
Tubing Anchor
Milled and
Underreamed Section
(8' High x 4' Dia.)
100-200'
Horizontal Drilled
Radial
12" Radius

Figure 2

STEAM SIMULATION
HISTORY MATCHING ELEVEN STIMULATION CYCLES
OIL AND WATER PRODUCTION VS TIME

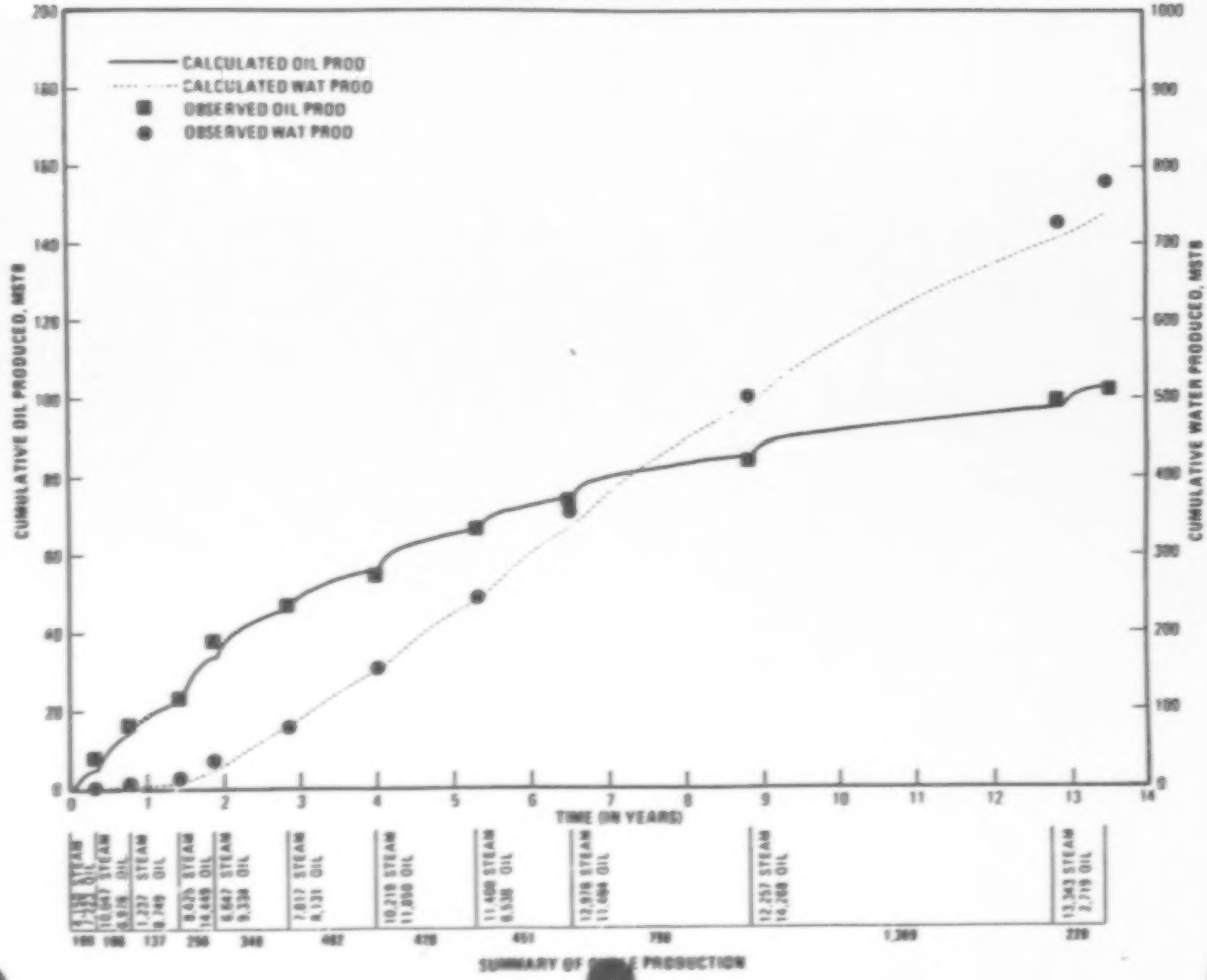


Figure 3

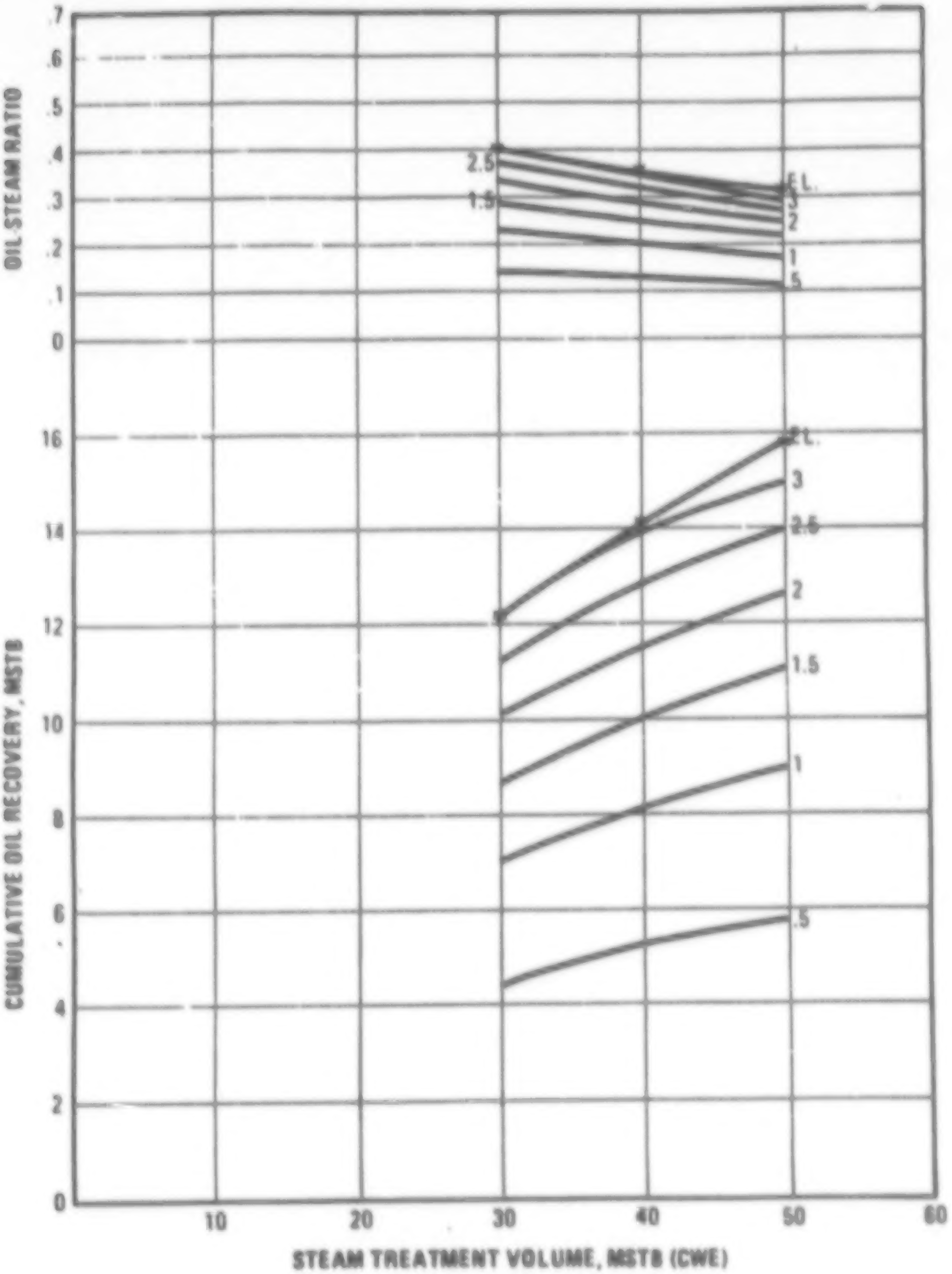
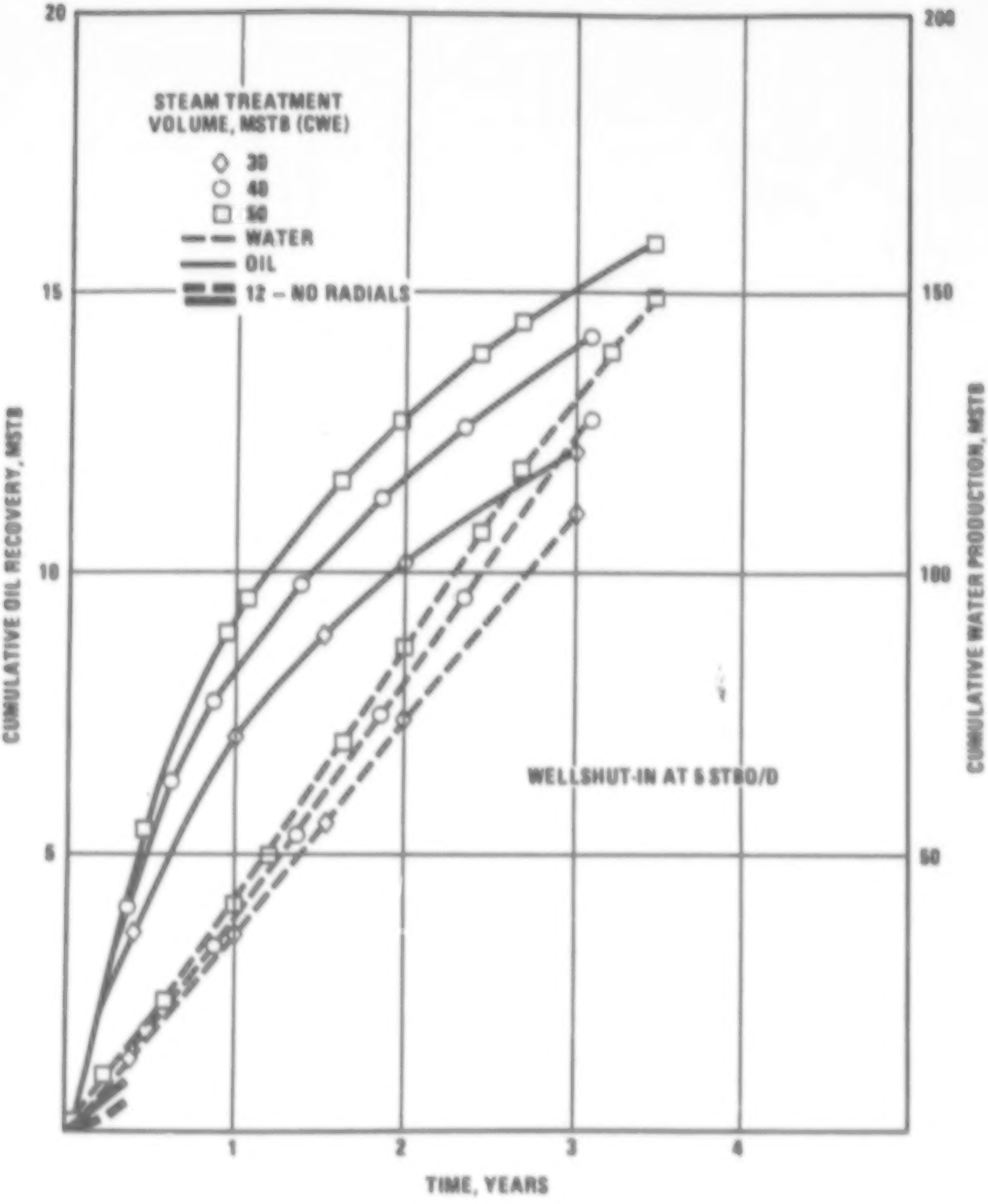

OIL-STEAM RATIO
.7
.6
.5
.4
.3
.2
.1
0
2.5
1.5
E.L.
3
2
1
.5
CUMULATIVE OIL RECOVERY, MSTB
16
14
12
10
8
6
4
2
0
E.L.
3
2.5
2
1.5
1
.5
10
20
30
40
50
60
STEAM TREATMENT VOLUME, MSTB (CWE)

Figure 4

OIL AND WATER PRODUCTION AFTER STEAM STIMULATION WITH RADIALS



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Horizontal Radial Drilling System

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This paper was presented at the SPE 1985 California Regional Meeting, held in Bakersfield, California, March 27–29, 1985. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write SPE, P.O. Box 833836, Richardson, Texas 75083-3836. Telex: 730989 SPE DAL.

ABSTRACT:

A high pressure, water jet drilling system has been developed using a new force system to concurrently drill a bore hole and place a metal tube in the bore hole.

The first commercial application has been horizontal radials for shallow heavy oil reservoirs. Many radials may be placed at the same elevation. Logging, and completion techniques have been developed.

I. Introduction

Over the past five years Bechtel Investments Inc & Petrolphysics Ltd. have been developing a new drilling system. The initial goal of the work has been to provide multiple horizontal drain holes or injection radials in unconsolidated heavy oil reservoirs via existing wells. In this paper we shall discuss the technology which has been developed to achieve that goal. We will also comment on other applications of this technology.

In this paper the term "radial" refers to the approximately 4 inch radial bore drilled into the formation. The term "production tube" refers to the 1¼ inch metal ERW tube placed in that bore.

A. System Technical Objectives

The following Project Technical objectives evolved from the primary goal:

1. Provide multiple, generally horizontal radials of predetermined direction, 100 to 200 feet in length from a single existing oil well, all from the same depth.
2. Drill a 100-200 foot hole rapidly, approximately 4 inches in diameter, through an unconsolidated formation.
3. Place a 1¼ inch OD production tube within the 4 inch diameter bore hole in the formation while drilling is in progress.
4. Cutoff the production tube, as required, downhole.
5. Log the individual production tube in three dimensions.
6. Provide perforations and sand control, if desired.

B. System Technology Summary

Early in the system development, a decision was made to employ a 10 to 12 inch radius turn from the vertical to the horizontal so as to be able to penetrate shallow or thin formations and to minimize underreaming. An erectable whipstock containing a combination of slides and rollers has been developed to effect this bending and straightening process.

The drill system uses 8,000-10,000 psi water for water jet drilling and can be adapted to commonly used additives. The drill bores an approximately 4-inch diameter radial within which it progressively places a 1¼ inch OD carbon steel production tube as it proceeds through the formation. The jet drill head does not rotate and delivers in excess of 1,000 hydraulic horsepower to the formation.

For drill propulsion, a totally new push-pull process has been developed. Specifically, the drill penetrates the formation in self-regulated movements propelled by internal static fluid pressure. Forward velocities can be controlled from a low of 6 feet per minute to a high of 120 feet per minute. As the drill moves through the formation, the anterior portion of the 1¼ inch tube is

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References and illustrations at end of paper.

maintained in tension. The internal static pressure provides a pulling force of 4000-8000 pounds. This tension force tends to keep the production tube straight which aids directivity for the system.

Methods have been developed to provide regulation of the forward speed of the drill which in turn tends to control drill inclination or vertical trajectory. Among these are a cable tail restraint attached to the tail of the radial.

The drill system has been principally tested in unconsolidated California reservoirs of 500 to 2,600 feet depth, such as Bakersfield (Kern River), Taft, and Brea (Olinda). The drill has penetrated through cobbles of hard crystalline rocks for short distances, as confirmed by experiments down shallow caissons where drilling progress can be seen directly. No work has yet been done in continuous consolidated formations. The system has effectively penetrated thick cement. An important part of the system is to log the drill trajectory. Normal logging equipment will not bend around a 12 inch radius. Hence, entirely new flexible logging and electronic packaging systems suitable for downhole application have been developed and are being applied. This technology is being extended to provide three-dimentional trajectory maps of the radial location.

For sand control of highly deviated or horizontal wells in unconsolidated formations, an integrated technology of radial completion is being developed. Operational applications examined for the system involve either production, injection, or both. The initial economic objective for the system was to provide a capability to get a quick production response. Hence, a huff-and-puff approach was initially applied. The technology is applicable also to steam drive or injection.

II. Systems Theory and Functioning

A. Drilling and Propulsion

The basic cutting, drilling and propulsion systems uses hydraulic forces. These forces concurrently (a) cut the formation, (b) pull forward the drill head attached to the production tube and (c) push forward the tail of the production tube. These forces and functions will be separately discussed.

1. Cutting

The basic cutting mechanism is an array of nozzles in the drill head. Each nozzle in the array achieves about 900-1000 feet per second exit velocity. The combination of water jets cuts a cavity of about 4 inches diameter in unconsolidated formations.

In consolidated formation materials the array of nozzles creates an alternating pattern of compressive and tensile forces in the rock such that spalling occurs continuously, even in very highly consolidated cobbles and rocks as are often found bedded in oil formations near Bakersfield. The combined jets also wash away cuttings from the area around the drill head. The measured nozzle velocity coefficient of the drill head is in excess of 80 percent.

2. Pulling Force

The production tube is 1¼ inch OD, 1.03 inch ID A-606 carbon steel, electric resistance welded reeled tubing (ERW). When the area of the nozzles is subtracted, the net internal cross sections of the drill head is about .8 square inch. Hence, excluding the jet reaction force, at 8000 psi net drill head pressure, the gross force from fluid static pressure on the backside of the drill head is about 6000 pounds. This force literally pulls the radial through the formation. This force also initially aids in moving the 1¼ inch tube through the whipstock.

To understand why this pulling force exists, consider a simple elongated vessel with closed ends, which is filled with a pressurized fluid. The axial forces on the closed ends balance out, so there is no reaction force on the vessel. Now if a hole is cut in one end of the vessel, the pressurized fluid exits through the hole and exerts a reaction force on the vessel. Next, consider that a tube with one end closed is placed in that hole and that a seal is provided in the hole so the tube will slide with respect to the vessel. The result is that the tube will be ejected much like a projectile by the static force on its closed end. This is the principle which has been applied to provide a pulling force on the production tube.

By placing suitable nozzles or holes in the closed end of the tube, or drill head, the water jet cutting system just described is provided. Thus for this drilling system, both the static and dynamic properties of the pressurized water jet cutting fluid are concurrently applied.

In our drilling system, the production tube begins vertically, proceeds around a 90° whipstock turn and enters the formation horizontally. As later described these same fluid pressure forces are further exploited to control the system. The overall drilling system configuration is shown in Figure 1.

3. Pushing Force

The production tube wall is .109 inches

thick. A simple configuration of the system is shown in Figure 1 - Overall Drilling System. Therein the posterior of the production tube is vertical and contained in a sealed chamber made up of the string of drill pipe down to the whipstock. This string operationally terminates in a high pressure, sliding seal system riding against the OD of the 1¼ inch production tube.

Within the vertical tubing string holding the whipstock and containing the production tube, the high pressure water is at 9000-10000 psi. The water exerts a force on the cross-section of the tail of the .109 inch thick production tube of about 3500 pounds. This force helps push it through the seal/whipstock system. This force is reduced by any net cable restraint forces. The result is a total push/pull forward gross force on the projection tube of about 9500 pounds less net cable restraint forces. As later discussed, other restraint or pushing force systems can be applied to control or enhance the gross forward directed force.

B. Whipstock

The next major component of the system is the whipstock. The whipstock provided two separate capabilities or functions that are totally integrated into one tool. The first set of components consists of the slides and wheels which enable the production tube to move initially from the vertical, around the 90° whipstock turn, through the straightener and out horizontally into the formation. The second set of components functions only during the passage of the tube through the formation. While moving out into the formation the production tube automatically lifts itself off the bending wheels and slides, which reduces friction.

In this process the metal production tube moves through a 12 inch radius, 90° turn very rapidly. The reason for the sharp turn radius is threefold.

1. To assure suitable placement in thin formations
2. To minimize the diameter of an underreamed hole or a slot for whipstock erection.
3. To keep the metal tube at high stress under the combination of pushing, pulling, and bending forces, plus internal fluid pressure.

The result is that the electric resistance welded production tube is highly stressed and is in a plastic state. Hence, large deformation of the tube can be accomplished at low incremental stress. To provide a space into which the whipstock can be erected, a series of high pressure hydraulic underreaming tools has been developed. These create a space of up to four feet in diameter. Such a large underreamed hole diameter is not possible with conventional mechanical underreamers within the constraints of the casing sizes characteristic of the typical older existing wells in California.

Two of the most time consuming tasks in placing radials involve the large diameter (48 inch) underreaming and repeatedly tripping of the whipstock to the surface to provide the mulitple radials. The second-generation whipstock, which is just coming out of research, requires only one-half that diameter of underreaming. These new tools also permit placing multiple radials without tripping to the surface between radials. The new tool is a repeater, rather than a single shot.

C. Control of Direction

The jet drilling system creates a generally round radial bore in the formation of about 4 inches diameter. Of course, consolidated areas or formation inhomogeneities affect the radial section. But, because the production tube is under tension as it enters the formation, it has a natural tendency to go straight, as does the resulting bore hole.

The velocity of the production tube and the volumetric flow rate of the high pressure water both have a strong bearing on radial pitch or inclination. Typical velocities of 20-120 feet per minute cause the radial to rise. Conversely, lower velocities cause the trajectory to droop downward. The precise downhole effects are not experimentally known. But one model is that at higher velocities the larger cuttings are probably not slurrified out of the way fast enough and may pile up ahead of, or under the drill head, causing it to rise. Conversely, at lower velocities the sorted cuttings may be more thoroughly washed out so that the drill would tend to droop as a cantilever beam, and move progressively downward.

For actual operations, the drill is started at lower velocities and the velocity is progressively increased as the radial progresses outward.

D. Velocity Control

To provide control of velocity, especially during progress through the whipstock and during initial entry into the formation, a cable restraint is applied. This consists of a cable truck, a wellhead high pressure grease seal and a removable plug at a tail of the production tube. The plug is removed after a run to permit the entry of logging tools. Of course, the restraining cable instrumentation gives a real-time indication of production tube movement.

E. Instrumentation and Logging Equipment

1. Drilling Instrumentation

To control the production tube during drilling, two variables are monitored in real time.

a) High pressure water pressure and flow

b) Production tube displacement and velocity in terms of cable movement

2. Logging

Because of the 12 inch radius turn through the whipstock, the logging instrumentation must pass through this 1 inch internal diameter production tube at a 12 inch turn radius. Rigid conventional instruments won't pass and no gyroscopes are available which are small enough to pass through the tube. Hence, completely new types of mechanical sensor instruments and packaging have been developed.

The key to these new logging systems is a packaging concept which combines several conflicting properties. The packaging must be soft and yielding, yet supportive around the electronics and sensors. The package must be sufficiently tough and strong to take external abrasion, pressure and shock. These resulting flexible logging systems currently provide a reliable and reproducible printout of inclination or pitch accurate to 1°. Instruments in test are expected to do the same in yaw or azimuth in the field.

F. Sand Control and Downhole Completion

The requirements of a 12 inch radius whipstock turn and a thin ERW production tube created a need for a new procedure of tube in-situ cutoff, in-situ perforation, gravel packing and flexible lining of the production tube. These technologies are in commercial usage or on test.

G. Well Head and Surface Equipment

Throughout the system development program, standard oil field equipment has been used where possible. Hence, the surface equipment is conventional. Pump power is supplied by a 1600hp/10000 psi frac pump. The rigs used are generally double stand, work-over rigs. Logging trucks are conventional.

Equipment for measuring production tube movement, instrumentation for fluid pressures, flows, cable tension, etc. are all conventional oil field hardware and function well in this application.

III. System Applications

The initial application of the drilling system is in shallow, heavy oil reservoirs in the San Joaquin Valley and the Los Angeles basin. Both huff and puff and pure injection commercial applications have been done.

For these reservoirs the system has been applied to provide more than three hundred radials in many wells. In general, four radials are provided in each well. All are at the same depth, as shown in Figure 2 - Typical Vertical Radial Patterns. But, if desired, many more than four radials can be placed at the same elevation as shown in Figure 3 - Typical Aerial Radial Patterns.

The drilling system is not limited to horizontal shallow, 100-200 foot radials, nor is it limited to a 1¼ inch production tube nor a 4 inch radial bore. The system can work vertically and we believe it can place very long and large tubes. Hence, among the applications other than the initial one which may have potential value are:

a) Offshore reservoirs
b) Consolidated formations and long radials
c) In-situ coal gasification or gas drainage radials
d) Waste disposal
e) Mineral recovery by solution mining

Conclusion:

A new concept of drilling a bore and placing a tube within that bore has been developed and applied in existing California oil wells. The technology has been successfully applied to providing multiple horizontal radials at the same level in a single well. Suitable logging, and completion techniques are in hand. The technology has potentially broad application to many petroleum and other resource drilling needs.

Acknowledgment:

This technology has been developed by a team of many engineers and scientists, particularly: Randy Anderson, Harvey Brush, Richard Cummings, Eric Dickinson, Herman Dykstra, Harold Forsen, Dale Hackney, Charles Harper, Stanley Hutchison, Richard Jensen, Donald Klucker, Raif Kulunk, Charles Mackey, Sherman May, John Morrison, Irving Odgers, David Rabb, Donald Shepley, Steve Soegaard, Audrey Sutton, George Wang, and Archie Wilson. The authors are particularly grateful to Bechtel Investments, Inc. for their generous technical and financial support of this effort and this publication.

Reference:

1. Based upon reservoir studies undertaken for Bechtel by Scientific Software Intercomp, a 100 foot, or at most a 200 foot radial, is all that is required for heavy oil production or steam injection. Longer radials are not useful in these typically low pressure reservoirs. This is more fully discussed in the paper: "An Innovative Methods of Drilling Horizontal Boreholes," by Larry E. Pendleton and A. Behrooz Ramesh on February 20, 1985 at the Heavy Oil and Oil Sands Technical Symposium,

University of Calgary, Calgary, Alberta CN 2500 University Dr., N.W., Calgary, ALBT T2N1N4. A copy of this paper may be obtained from the University of Calgary or from the authors.

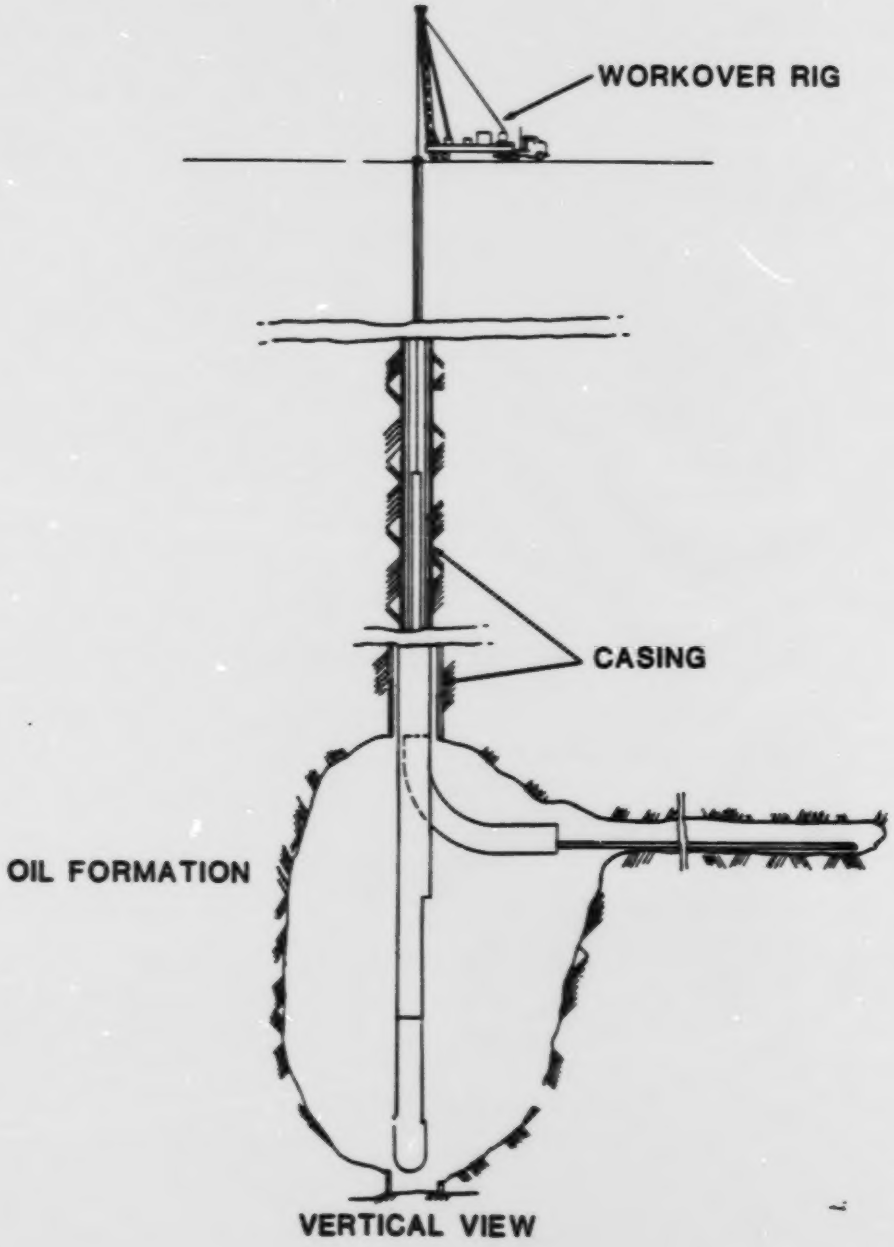
WORKOVER RIG
CASING
OIL FORMATION
VERTICAL VIEW

Fig. 1—Overall drilling system.

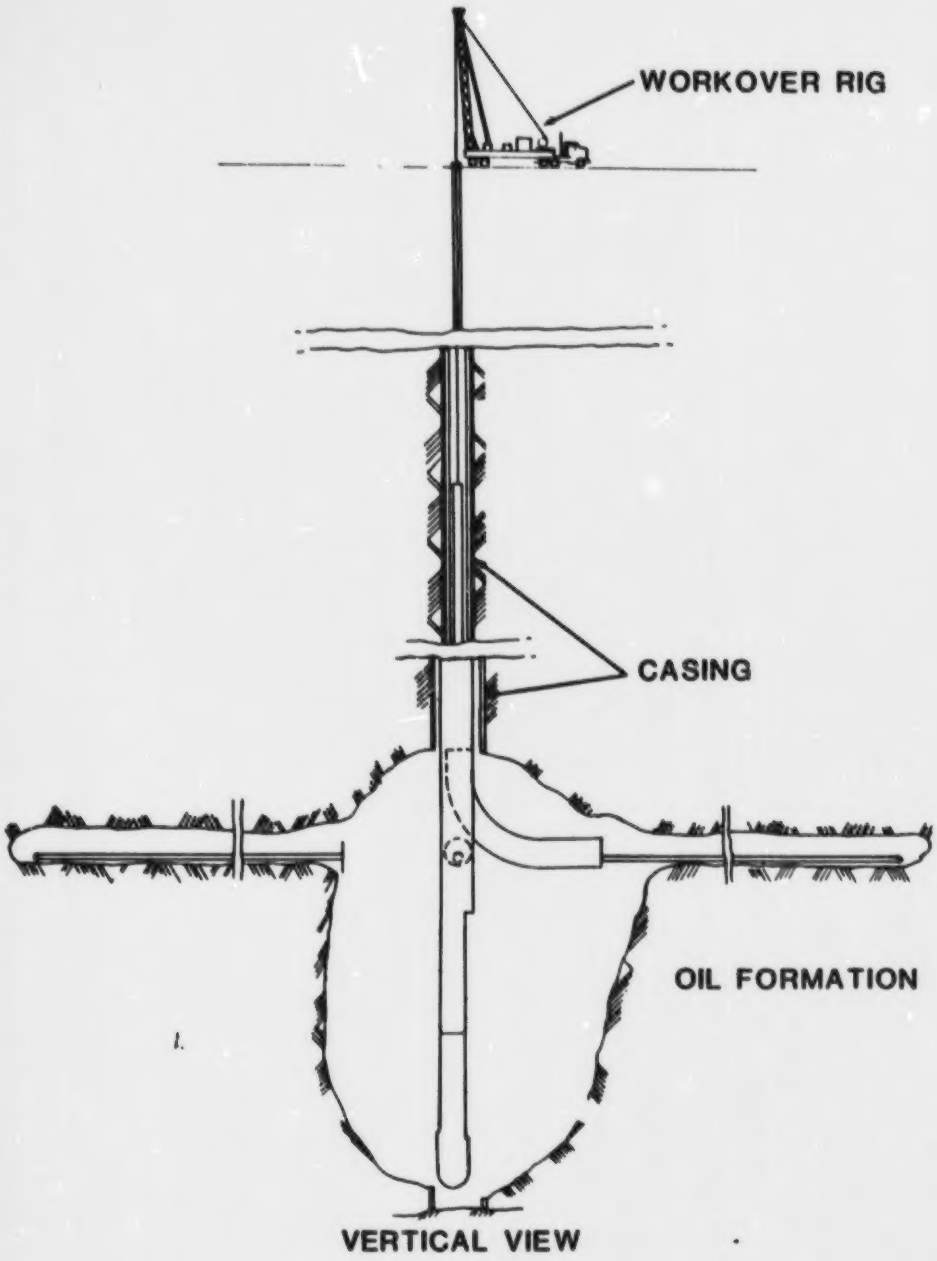
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Fig. 2—Typical vertical radial patterns.

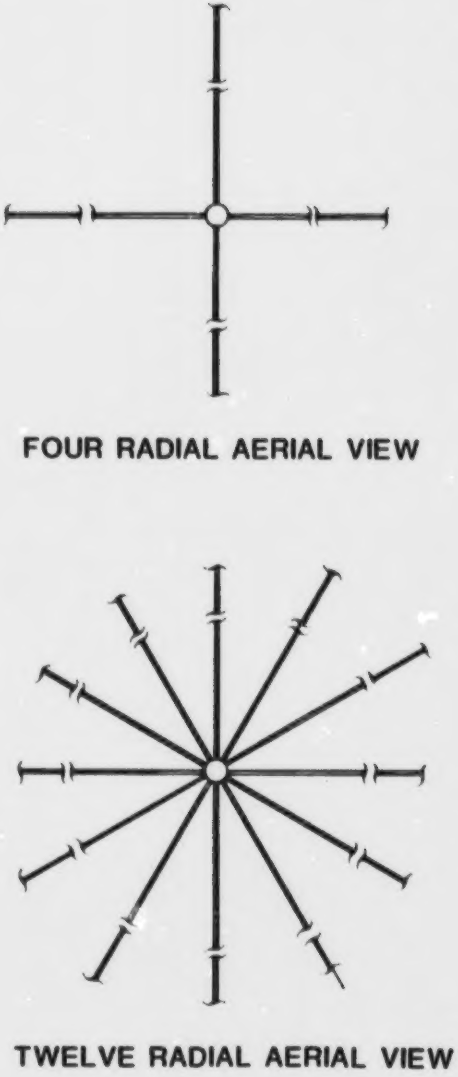
FOUR RADIAL AERIAL VIEW
TWELVE RADIAL AERIAL VIEW

Fig. 3—Typical aerial radial patterns.

28.1

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Information

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OIL SANDS RESEARCH DEPARTMENT

TITLE: INNOVATIVE METHODS FOR HORIZONTAL DRILLING DEVELOPED BY BECHTEL/PETROLPHYSICS LTD. AND THEIR POTENTIAL FOR THERMORECOVERY OF OIL SANDS

SPEAKER: Wade Dickinson, Petrolphysics
University of California
Berkley - Visiting Professor

DATE: Thursday, December 4, 1986

TIME: 1:30 p.m.

PLACE: Clover Bar Main Conference Room

ABSTRACT

A new horizontal drilling process was developed and tested by Petrolphysics. It differs from conventional drilling and offers new features such as:

- horizontal holes are drilled from vertical wells and requires a turning radius of only 30 cm (12").
- as many as 24 horizontal holes may be installed in any particular horizontal plane,
- a drilling method which involves hydraulic jetting at rates from 3 to 30 m/min,
- the drilling process is more economical than conventional horizontal drilling methods and the time required for installing four horizontal holes in shallow unconsolidated formations is normally less than 60 h.

Drilling from existing conventional vertical wells of long horizontal and deviated wells opens a new era for thermorecovery of heavy and extra-heavy oil as well as for improving performance of conventional reservoirs.

Potential application of the new drilling system to new and old oil sands reservoirs will conclude the presentation.

The new drilling system in operation will be presented using slides and videocassette.

This seminar is open to ARC, universities and ACCESS members.

Visitors who wish to attend are asked to contact Dr. Peter Toma, Dr. Peter Tremaine or Ms. Phyllis Kozak at 464-9212.

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Alberta OIL SANDS
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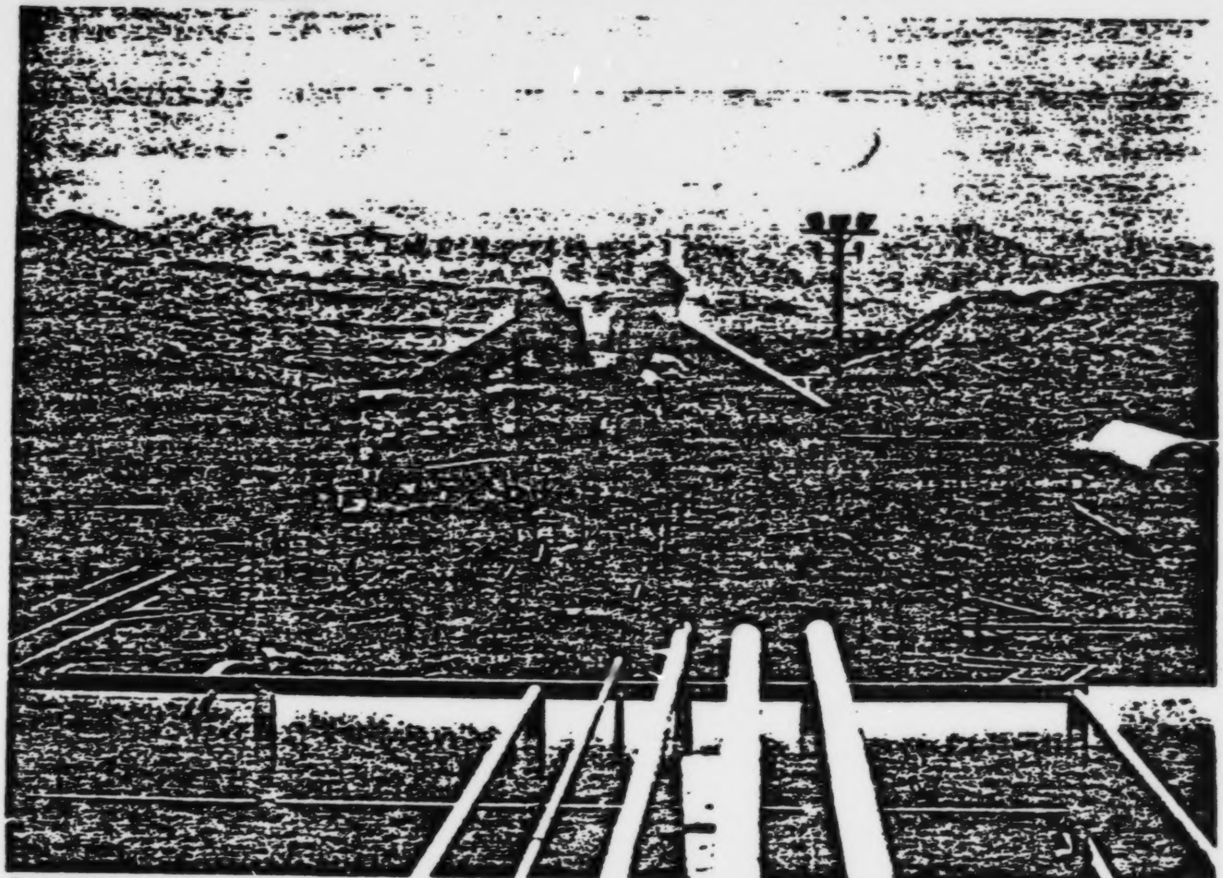

Eight pump units clustered around a single wide-diameter hole mark the site of Cornell Heavy Oil Process Inc.'s "hot plate" heavy oil recovery project in California's Kern River field.

"Hot plate" cooking in California

BILL RINTOUL
Contributing Editor

THE FIRST FIELD test of the "hot plate" heavy oil recovery method became operational in July in California's Kern River field.

If the technique is successful, it could have significant implications for the production of heavy oil. It's anticipated that the innovative method's application of steam to the Kern River oil sand will make it possible to recover about 75% of the oil in place. That's substantially more than the average 50% recovery forecast for conventional steaming operations in the field.

Beyond Kern River, the method would appear to have use in many of the world's heavy crude fields. Since the Kern River test was announced 2½ years ago, there have been inquiries about the possibility of using the method not only in other fields in the U.S., but also in the Cold Lake area of Canada, at a field in Germany and in the Orinoco tar sands in Venezuela.

The method was conceived as a means of making it possible to recover more oil in less time from fields like Kern River that contain hard-to-produce heavy crude. The average gravity of the Kern River oil is 13°.

$15 million investment

Cornell Heavy Oil Process Inc., of Dallas, TX, is the company backing the Kern River field test. Cornell and its predecessor, Barber Heavy Oil Process Inc., of Houston, TX, have invested approximately $15 million in the Kern River test, according to Frank Wimer, Cornell president.

Wimer said Cornell has been

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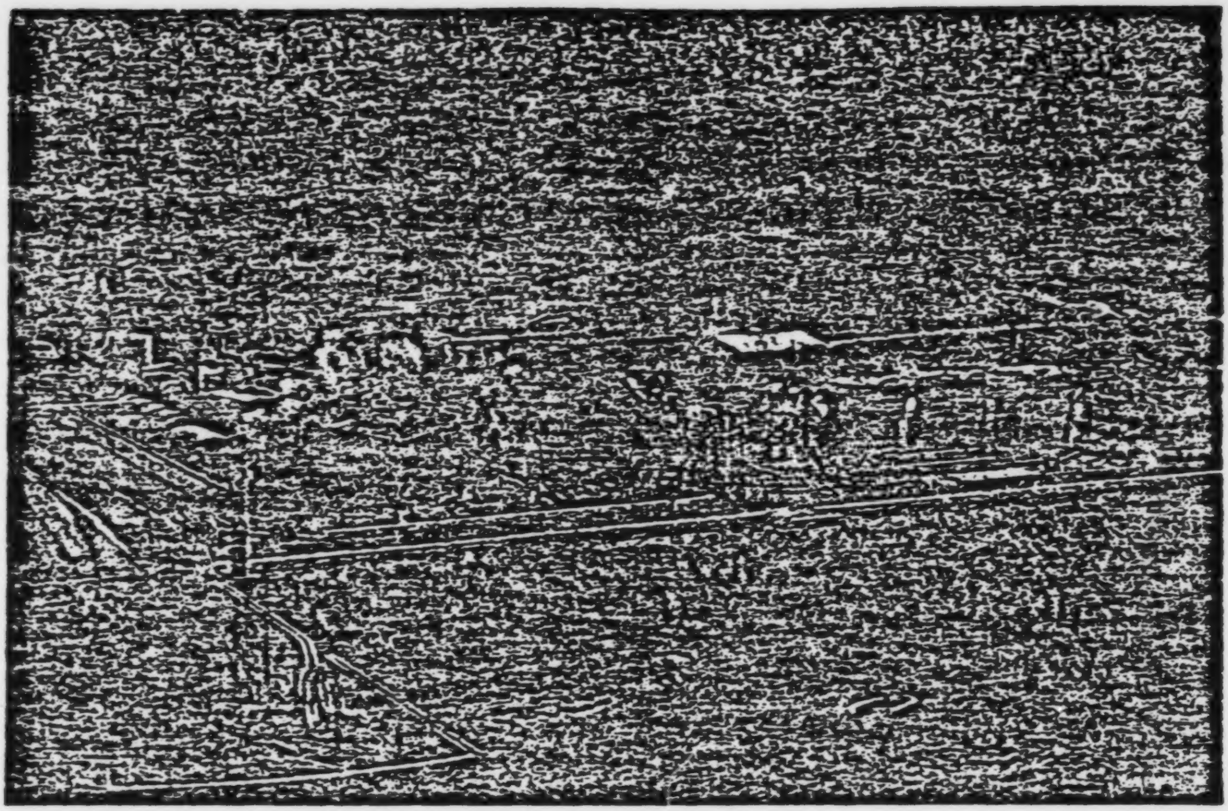


View of the Kern River site where Cornell Heavy Oil Process Inc. is testing the "hot plate" recovery method. Cornell uses a 50 million Btu/hr Thermotics generator with a Thermotics scrubber to generate the steam that's putting a section of Kern River oil sand on a "hot plate".

able to recover nearly 75% of the cost through the federal government's Tertiary Enhanced Recovery Program. In 1980, the project became the first to qualify for participation in the program, which made it possible for the qualifying company to deregulate the price of specified volumes of price-controlled oil to finance its investment.

After more than 2 years of field preparation, Cornell began injecting hot water in July to clean out and test the "hot plate" system built under the direction of Fenix & Scisson Inc., of Tulsa, OK, which serves as operator for Cornell.

The one-of-a-kind project basically involves a wide-diameter vertical shaft with a cavern near bottom from which eight horizontal shafts have been drilled.

The eight laterals lie near the base of the Kern River oil sand, which is approximately 80 ft thick. Their role is to serve as conduits through which steam is injected to create an effect like putting the oil sand over a hot plate.

An anticipated recovery of 75% of the oil in place is predicted by Wimer.

Stakes are high. The Kern River field is believed to have held in excess of 3 billion bbls of oil when it was discovered 83 years ago. The field has been tapped for 890 million bbls and is estimated to have approximately 1 billion bbls left that can be recovered by present technology.

Unless the "hot plate" method or some other innovative technique proves successful, hundreds of millions of bbls will be left in the ground.

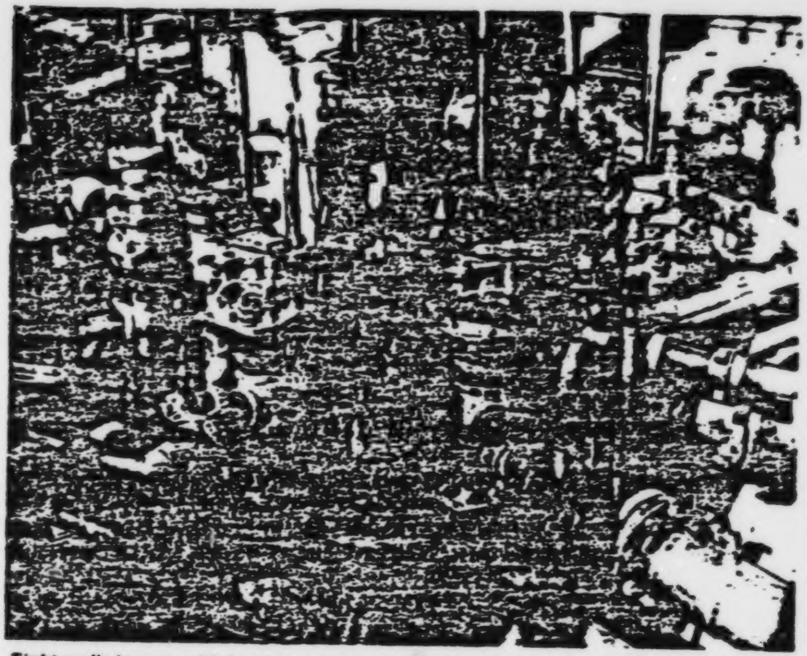
The site of the field test is a 25-acre parcel in Sec. 34, 28S-28E, Kern County, and it was acquired on a farm-out from Shell Oil Co. The parcel is at the eastern edge of the field, where oil sand is relatively shallow. It's of passing interest that the site is only 1 mile north of the pick-and-shovel discovery well where James and Jonathon Elwood found oil at a depth of 43 ft in the spring of 1899 to open the Kern River field.

For the initial phase of the operation, Cornell fired up the 50 million Btu-per-hour Thermotics steam generator at the test site to heat water to approximately 128 °F. for injection into the laterals. The objective was to clean out laterals and slots and check out the steam generation and injection systems.

Start-up essentially was trouble free. Cornell put away hot water at rates of between 3,000 and 3,300 b/d, then switched to low-quality steam.

After successfully checking out the steam generation and injection systems, the operator shut down the generator and began testing the production system. Initial production from the clean-up phase consisted of oil and water with very little sand. Along with checking out the production system, the operator used the production test to develop information on primary production before beginning to steam in earnest.

Plans call for cyclic steaming, with two or more laterals to be steamed at a time for about 30



Eight wells in one, with hardware to match. Surface view of the wellhead at the main shaft at the Kern River "hot plate" test site.

days, then shut in to soak for 5 to 10 days before the laterals are put on production. It's expected that at any given time there will be at least four laterals on production, with two others undergoing steaming and two soaking. Cornell envisions 5 or more years of operation.

Designed for 4,500 b/d

The production system has been designed to handle up to 4,500 b/d of total fluid. It's anticipated that the breakdown may be about 1,000 b/d of oil and 3,500 b/d of water.

Produced fluids will be piped to Shell's Kern River dehydration plant. The oil will be sold to Shell through a Lease Automatic Custody Transfer unit. Water will be cleaned up for use in steaming.

There are downhole gauges in the main shaft to monitor temperatures, formation pressures and stresses and strains on equipment.

The gauges are connected by cables to a Hewlett-Packard 9845B computer on the surface, which provides a readout that will enable the operator to optimize design for future projects.

On the surface there's also a television monitoring system with three cameras positioned in the top of the cavern. The cameras are designed to operate in temperatures of up to about 200 °F. They command a view that will enable engineers to look at such things as wellheads, expansion joints and the cavern walls.

Two 8-in. lines provide for air circulation into and out of the cavern, where the temperature shortly after start-up was 130 °F.

There are no plans to send anyone down the shaft, but the system has been designed so that if it is necessary to send someone down, it will be possible to do so. There's a skip that can accommodate two men. The skip runs on the two 8-in. air lines. It would be lowered by a crane. If it does become necessary to send someone down, the steaming operation will be shut down and the cavern allowed to cool.

The 491-ft-deep main shaft began life as a 7-3/4-in.-diameter corehole that was drilled in September, 1979 by Gary Drilling Co., of Bakersfield, CA, with a conventional rig.

Specialized Drilling Division of Santa Fe Engineering & Construction Co. handled the contract assignment of drilling a 7-ft-diameter hole around the corehole, using a Hughes Tool CSD-820 hydraulic rig leased from McKinney Drilling Co., of Nacogdoches, TX.

It took 8 days to cut the 7-ft-diameter hole, with one trip necessary to replace cutters on the bit. According to one calculation, the cuttings that were removed from the large-diameter shaft were equivalent to those that would be removed from an 8-in.-diameter hole drilled to 55,000 ft.

Each 15-ft joint of drill pipe consisted of two joints of pipe—an outside joint of 13-3/8-in.-diameter pipe, inside which was fixed a joint of 9-5/8-in. pipe. In drilling the shaft, the contractor used the reverse circulation method, pumping air and drilling fluid down the space between the two joints of pipe, which returned the cuttings to the surface through the inner joint. The introduction of air to the drill stem just above the bit created a lower hydrostatic head, which helped lift the drilling fluid and cuttings to the surface.

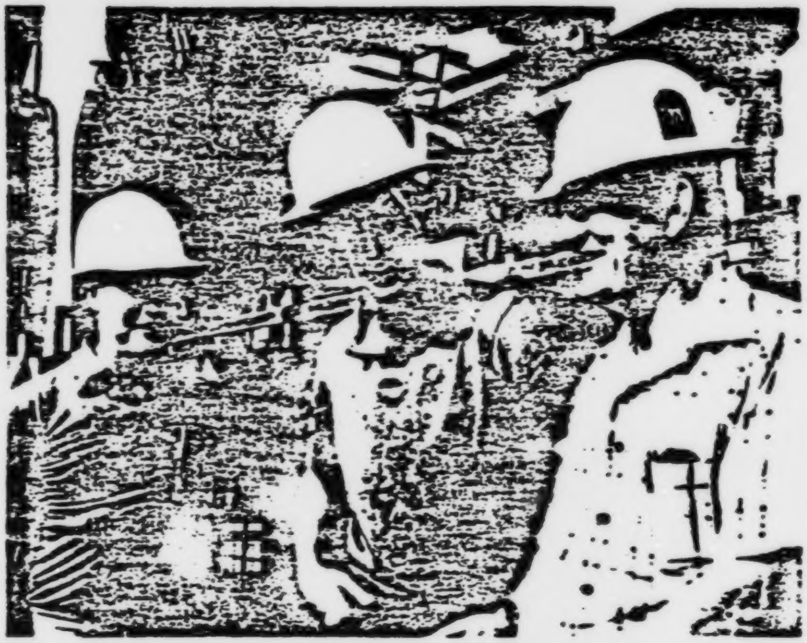
Inside the wide-diameter hole, the contractor cemented 5-ft-inside-diameter casing to a depth of 416 ft. The casing job took 5 days, with casing cemented at 116 ft in the first stage, 200 ft in the second stage and 100 ft in the third stage. Crews drilled out the casing shoe with a 56-in. bit and cleaned out to total depth.

After the hole was drilled and the rig moved out, surface installations were constructed, including a headframe, hoist and ventilation facilities.

Just below the casing point, hardrock miners enlarged the hole to flare out over a distance of 10 ft in a cone-like configuration into a cavern 31 ft in diameter. Cool air circulating down the hole through the ventilation system provided a working atmosphere of about 80 °F., which often was cooler than the surface temperature in the San Joaquin Valley's summer heat.

As miners cut the cavern, oil oozed out of the sand and ran down the walls, causing them to use plastic sheeting to hold the oil away while they put up metal screening for reinforcement before spraying Shotcrete on the walls. The Shotcrete, a mixture of sand, cement and aggregate, was mixed on the surface and piped down the hole to be shot out through a hose.

After the cavern was hollowed out, they put up a form to pour 3-ft-thick, reinforced concrete



Left to right, Jerry Emerson, lead foreman; Jeff Schrader, senior petroleum engineer; and Mike Huhn, operations manager at the $15-million project. All are with Fenix & Scisson, Inc., which serves as operator for Cornell Heavy Oil Process.

walls, forming a cavern 25 ft in inside diameter and 10 ft high.

Below the cavern, miners excavated another cone-like section to go back into the 7-ft-diameter shaft and construct a 30-ft, concrete-lined sump.

The cavern served as a work area from which the eight laterals were drilled through ports. The laterals include four that go out 430 ft and four that go to 730 ft. They radiate spoke-like from the cavern.

The unit used to drill the horizontal laterals was a hydraulically-powered auger manufactured by Richmond Manufacturing Co., Ashland, OH, for mining and other applications. A hydraulic pump working with a hydraulic motor in a closed circuit drove the gearbox that rotated the auger. Two hydraulic rams moved on rails, pushing pipe into the hole behind the auger. There was a cutting shoe on the end of the pipe string.

The drilling unit took up about 12 ft of the cavern's 25-ft diameter, allowing the three-man crew, sometimes four, enough room to work with pipe in 10-ft sections. Before starting the downhole work, Fenix & Scisson drilled 10 practice holes on the surface.

Drilling "top hole"

The initial step down the hole was to drill "top hole" at each of the eight laterals, boring back at 50 ft into the sand through the ports that had been built into the chamber. Blank 10-3/4-in. "surface" casing was cemented in each lateral.

The next step consisted of drilling the remaining footage of the laterals, taking four out to a distance of 430 ft from the main shaft and four out to 730 ft. Beyond the 10-3/4-in. blank casing, the laterals were cased with 8-5/8-in. slotted liners.

The biggest problem in drilling the laterals, according to Cornell's Wimer, was the variable nature of the oil sand. Wimer said sometimes the sand was almost fluid, sometimes clay and sometimes cobbles. In places they hit pockets of methane. In spite of problems, Wimer said the company succeeded in placing the laterals where they wanted to put them.

In the main shaft, there are 16 strings of casing, consisting of two strings for each lateral, including a 3-in. string down which steam is injected and a 4-in. string through which the lateral is produced. Two-in. tubing and 3/4-in. rods have been run in each 4-in. string so that the lateral can be produced on the pump.

Eight pump units have been set around the head of the shaft, consisting of one for each lateral. The units include three Lufkin 114s and five Lufkin 40s. The units are matched to the laterals according to the amount of fluid they're expected to handle.

In addition to the main shaft and the eight laterals, the operator drilled eight vertical wells to the bottom which were equi-distant between each of the laterals. Barnes Core Drilling Co. drilled the wells. They will be used as injectors if and when the project is converted to a line drive.

Along with the 50 million Btu-per-hour Thermotics steam generator that's being used on the test site there is also a Thermotics scrubber. Other equipment includes three 500-bbl storage tanks along with fuel, caustic and waste tanks. Two buildings on the site are being converted to serve as offices.

Mike Huhn is the operations manager for Fenix & Scisson, Jeff Schrader is senior petroleum engineer and Jerry Emerson is lead foreman.

Huhn, a graduate civil engineer from the University of Kansas, has had 15 years experience as a petroleum engineer, including 8 years with Cities Service Co. and 4 with the Department of Energy before joining Fenix & Scisson. Schrader, a graduate chemical engineer from the University of Arizona, has had 7 years experience in the oil industry, most recently with Tosco on the Colony Oil Shale project in Denver. Emerson spent 5 years with Occidental in Libya before joining Fenix & Scisson in April.

Mike Sharp is the adminstrative manager. There are 14 employees who work three shifts at the Kern River site.

During the construction phase, George Bailey served as project manager for Fenix & Scisson, and Bill Hoover handled surface installations. Bob Phelan served as operations consultant for Cornell.

Dr. L. Jan Turk and Dr. Ralph O. Kehle, inventors of the heavy oil recovery process, have served as general consultants. Both are of Austin, TX. □

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ASME Energy-Sources Technol Conf., New Orleans, Feb 12-16/84

(31)

A MODEL FOR JET PIERCING OF OILSANDS

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University of Alberta
Edmonton, Alberta T6G 2G8

ABSTRACT

The impact of a stationary confined high pressure water jet on a solid surface has been investigated. Flow visualization by high speed photography and measurements of average surface pressures show the action of the jet is to exert a series of discrete impulses rather than a steady force. It appeared more appropriate then to analyze the pressure data statistically to obtain the probability of occurrence of pressures above a critical value required for failure of the material. These probability values were then incorporated into a cutting model to predict jet piercing rates and expected maximum depths of penetration. Comparison of these model predictions with some limited field data was then carried out.

NOMENCLATURE

A,B - constants
d - nozzle diameter
D - tube diameter
K - initial cutting rate
P_d - jet dynamic pressure at the nozzle
p - pressure at piston surface
p_c - critical pressure required for failure of oilsands
$P[p > p_c]$ - probability that critical pressure is exceeded
$P^*[p > p_c]$ - minimum probability required for piercing to continue
z - standoff distance
λ - a parameter

INTRODUCTION

The feasibility of using high pressure water jets to supplement or replace mechanical drilling has been established (1-3). In particular, hole depths of up to 15 m in coal have been reported and depths to 60 m considered possible (4). The prospect then of substantially increasing the effective diameter of a drilled well in a controlled manner by piercing in Fig. 1 is promising. To assess the practicality of this application to an in-situ oil sands operation requires a correlation between the depth of penetration, time, material properties and jet parameters such as nozzle diameter and dynamic pressure. To this end a series of laboratory tests were carried out on an idealized down-hole geometry.

The characteristics of the jets were investigated both qualitatively by flow visualization and quantitatively by measuring jet pressure at the modelled cutting face. From these observations and measurements it was quite clear that neither averaged quantities nor peak values could adequately describe the highly fluctuating pressure. Instead the pressure signal has been analyzed statistically to obtain the probability that the pressure will exceed some threshold value for penetration to occur. Further, by relating the rate of penetration to this probability, the time to reach maximum penetration may be estimated.

In this paper the experimental results are summarized, a statistical analysis of the data described, and predictions based upon this analysis compared with some field test data.

EXPERIMENTAL EQUIPMENT AND METHODS

The laboratory tests were designed to study the

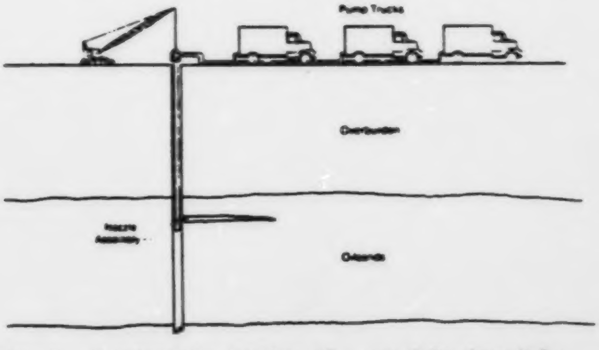

Fig. 1. A schematic drawing of a possible down-hole jet piercing operation

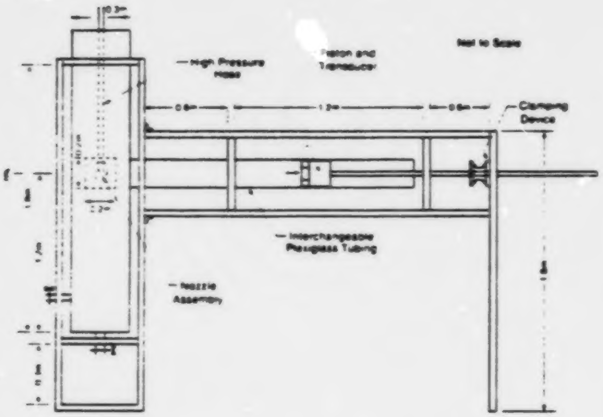

Fig. 2. A schematic drawing of the laboratory model of the down-hole piercing geometry

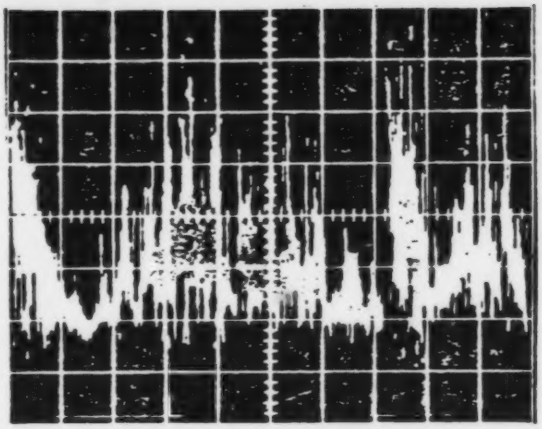

Fig. 3. A photograph of an oscilloscope trace of a typical transducer signal.
Dynamic pressure: 10 MPa Nozzle diameter: 1.6 mm
Standoff distance: 0.5 m
Horizontal scale: 5 ms/cm Vertical scale: 50 KPa/cm

flow of a high speed water jet in a simulated down-hole jet piercing geometry. The basic laboratory arrangement is presented schematically in Fig. 2. A vertical 30 cm square tube represents the well bore. This tube is open at the top but has a valved drain tube at the bottom to remove spent water. By adjusting the valve opening, water can accumulate in the vertical tube so that the characteristics of a submerged jet may also be studied. At mid-height and opposite to the nozzle assembly a connection is made for horizontal circular tubes. These tubes represent the hole being produced by the jet.

Since the diameter of the actual hole cut in the formation is unknown for a given set of jetting parameters, a set of four, solid-walled tubes were used for each set of cutting parameters. In addition to these tubes several tests were carried out with a porous tube having an open area of five percent. The motivation for these experiments came from field tests of jet piercing (5) in which it was noted that some of the spent water returned through fractures in the oil sands working face and also from previously drilled holes. Hence the assumption of a solid wall appeared to be too severe and some tests with a porous wall were in order. Which of these tubes most accurately reflect the actual situation will be determined by comparison with the field data.

Inside each tube a moveable piston was used to vary the length or depth of the hole and a transducer was mounted in the face of the piston to measure the pressure. The transducer consisted of a 25 mm diameter, 2.5 mm thick steel disc supported on its circumference. Strain gauges on the rear side of the disc were used to measure the deflection produced by the jet. The transducer was calibrated statically using air pressure and consequently the resulting measurements indicate an equivalent, spatially averaged pressure of the jet on the transducer face. The spatial averaging occurs because of the large sensing surface area (large relative to the characteristic length scale of the jet) and poses a problem when developing the cutting model, as shall be discussed in a later section.

The experimental investigation encompassed the following variables:

nozzle diameter (d)	1.59, 2.38, 3.18 mm
jet dynamic pressure (P_d)	1.8 to 34.0 MPa
tube diameter (D)	38.1, 50.8, 76.2, 101.6 mm, 50.8mm (porous)

The high pressure water for these tests was supplied by a piston pump driven through a variable speed drive by a 30 KW electric motor.

An example of the response of the transducer to the water jet is shown in the oscilloscope trace of Fig. 3. The signal is highly irregular with peak values many times larger than the mean. In order to quantify this signal the transducer output was processed to obtain the probability that at any instant the pressure (p) is a given value, i.e. the probability density function (PDF), f(p). This was accomplished by sampling the transducer signal and plotting a frequency distribution curve. This function was then integrated:

$$\mathrm{CDF}(p) = \int_{-\infty}^{p} f(p)dp$$

to give the cumulative density function (CDF), which is central to the analysis described in a later section. An example of each of these curves is presented in Fig. 4. A PDF and CDF were determined for each set of jet parameters, tube diameter and piston position. In addition to measuring the PDF, the time-averaged pressure acting on the transducer for each set of parameters was also determined.

EXPERIMENTAL RESULTS

Flow Visualization

Flow visualization was accomplished by using a Hycam high speed movie camera operating at approximately 5000 frames per second to record the structure of the unconfined jet and also the flow in the horizontal tubes when the jet was confined. These observations will be described first for they are very helpful in interpreting the quantitative data.

In Fig. 5 a few frames from a high speed movie of the unconfined jet have been reproduced and there are

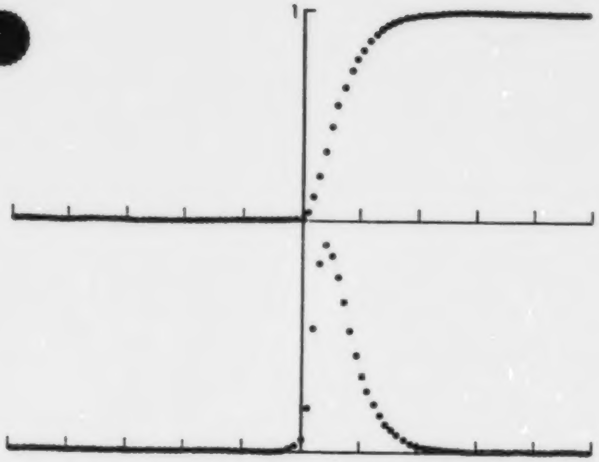

Fig. 4. An example of the probability (lower curve) and cumulative density function of the transducer signal. Dynamic pressure: 20.5 MPa, Nozzle diameter: 1.6 mm, Standoff distance: 0.5 m and Horizontal scale: 180 KPa/cm.

several features of the flow that should be noted. The most obvious one is that the jet is not a steady, continuous stream, but instead consists of separate droplets and slugs or packets of water. In addition, it was noted that the droplets and slugs did not occur totally at random, but instead in a series of trains of water separated by gaps which contain little or no liquid. Each train began with a slug or packet of water at the front which was trailed by a great many water droplets as demonstrated in the photographs of Fig. 5. There was a great deal of variation in the details of the structure of each train but the main structure of a slug followed by droplets was repeatable.

The formation of the trains is a consequence of the method used to produce the high pressure water jet - a piston pump. An examination of the time between trains from the high speed film, and a spectrum analysis of the transducer signal showed frequencies which correlate with the pump rotation rate. The structure within each train is explained by the variation in the pump piston speed during the discharge stroke. At bottom dead center (BDC) of the discharge stroke, the piston and hence the water speed is zero. During the stroke, the piston will accelerate to some maximum speed and then decelerate to zero again at top dead center. Consequently, the train of water produced by the stroke will have a speed varying from zero at the leading and trailing edges, with a maximum between. The water having the higher speed will overtake the slower moving water at the leading edge to form a slug and the slower moving water at the rear of the train will trail behind.

In addition to this speed modulation imposed by the pump, the entrainment of air is also a factor in the break up of the water jet. A further factor in the structure of the jet is the nozzle geometry. This can be an important one (see, for example, reference 6), in that the rate at which the break up occurs can be decreased or increased, but the features of the behaviour described above would remain unchanged.

These observations of the structure of the jet can now be used to explain the nature of the transducer signal of Fig. 3. Instead of a force being exerted continuously on the transducer by a steady jet, a series of collisions or impacts occur producing large discrete impact forces. This signal character can still be seen in Fig. 3 even though the signal has been spatially averaged because of the large sensing area. It is this

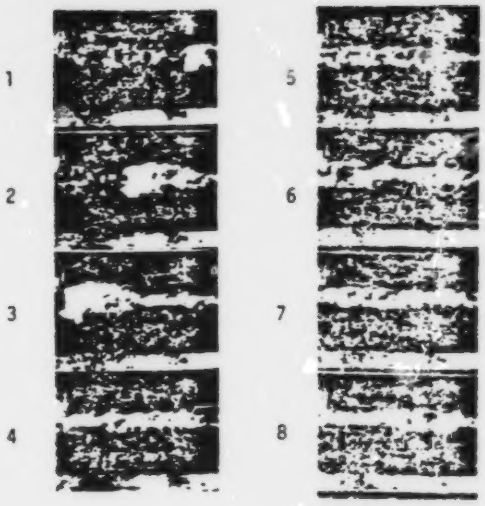

Fig. 5. A sequence of frames from the high speed movie of the unconfined jet. Two milliseconds between frames. Flow is from right to left. Dynamic Pressure: 2 MPa, Nozzle diameter: 2.4 mm and center of frame is 0.5 m from nozzle.

observation of discrete events that prompted the examination of the process as a stochastic one and analysis of the signal statistically.

Confining the jet by directing it into a closed tube represents an even more complex problem than the unconfined jet, for now the spent water must return through the same tube. Here the flow visualization indicates that the flow be divided into three regimes. Given a particular set of jet parameters and a small piston to nozzle (standoff) distance, the characteristics of the jet are unchanged from those of the unconfined jet The water impinging upon the piston face spreads radially across the surface to the tube wall, and then is turned and flows back towards the nozzle along the tube wall. If the standoff distance is sufficiently small, the water at the top of the wall remains there and leaves the tube into the vertical section concentric to the jet. If the distance is greater. the water will fall along the wall of the tube and flow into the vertical section along the bottom of the tube. Thus, the first flow regime is characterized by no interference of the returning spent water and the jet impinges directly on the cutting face.

As the standoff distance is increased, the jet spreads until interference between the jet and the returning water occurs. This interference results in some dissipation of the jet before it reaches the piston face and a hold back of the returning water. The consequence of this is a slug of water between the piston face and the incoming jet (Fig. 6). In this flow regime the presence of the slug is intermittent: appearing and then collapsing depending upon the portion of the jet train impacting on the piston. A further increase in standoff distance results in formation of a permanent slug. Greater standoff distances only lengthen the slug and the incoming jet is dissipated at the upstream end. Once the slug forms, the pressure at the piston face remains relatively constant and pressure peaks are much less pronounced, marking the third flow regime. The distance at which slug forms is dependent upon the nozzle geometry, flow rate and the diameter of the tube. At present no attempt has

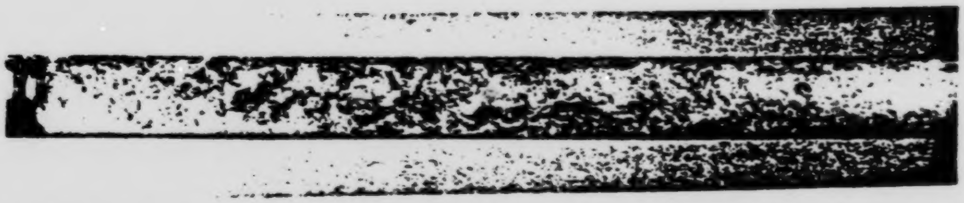

Fig. 6. A photograph of the slug of water that forms between the piston and the incoming jet. Dynamic Pressure: 10 MPa, Nozzle diameter: 1.6 mm, Standoff distance: 1.2 m and Tube diameter: 25 mm.

been made to develop a correlation to predict this distance.

Quantitative Results

For each combination of nozzle diameter, pressure, tube size and standoff distance the time-averaged value along with the PDF and CDF of the pressure on the piston face were obtained. The time averaged pressure at different standoff distances is shown in Figure 7a for small tubes, in Fig. 7b for the larger tubes, and Fig. 7c for the porous tube for various nozzles and dynamic pressures. The average pressure has been nondimensionalized by the dynamic pressure at the nozzle and the standoff distance with the nozzle diameter. It will be noted in several cases that the pressure becomes constant beyond a particular value of the standoff distance. This is most prevalent in those cases of the small diameter tube and large nozzles (i.e. high flow rates). It was found that the standoff distance at which the pressure becomes constant correlated well with the flow observations of slug formation (the third flow regime). Once the slug forms, the piston is separated from the jet by an essentially stagnant pool. Consequently the jet dissipates itself in the front of the slug and the pressure is transmitted through the slug to the piston face. Hence, discrete impacts or collisions do not occur at the transducer face and the peaks in the transducer signal are substantially reduced. As the standoff distances are increased, the slug becomes longer and the leading end remains in approximately the same position. Consequently, the measured force on the piston remains constant and was found to correlate very well with the momentum flux in the jet at the nozzle.

In the porous wall tube, spent water drains away from the cutting face easily through the tube wall, thus preventing slug formation. The average pressure then decays in a similar manner as for the larger tubes, as shown in Fig. 7c.

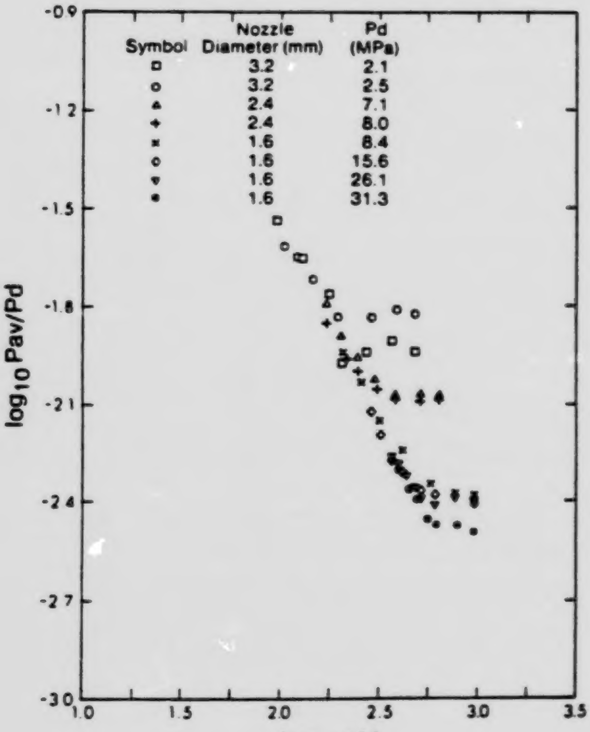

Fig. 7(a) The ratio of the average transducer pressure to nozzle dynamic pressure vs. the ratio of standoff distance to nozzle diameter. 38.1 mm tube.

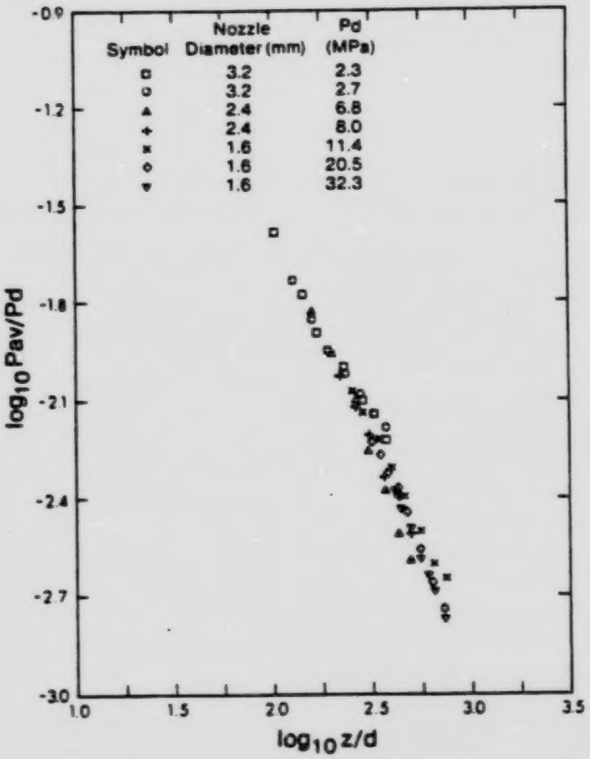

Fig. 7(b) The ratio of the average transducer pressure to nozzle dynamic pressure vs. the ratio of standoff distance to nozzle diameter. 101.8 mm tube.

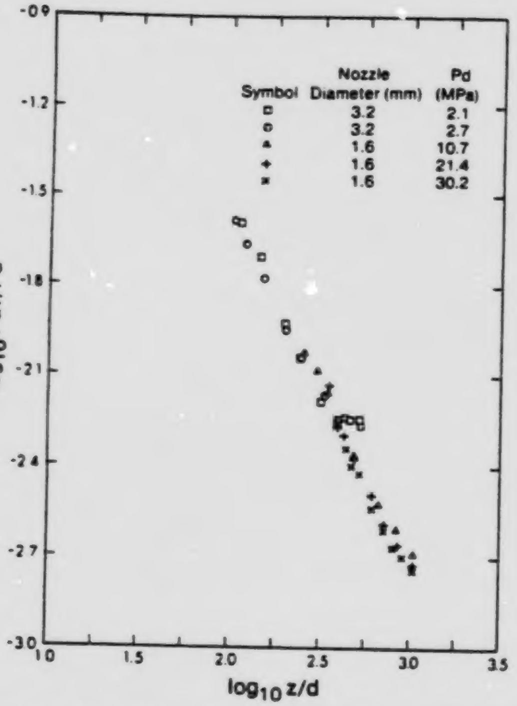

Fig. 7(c) The ratio of the average transducer pressure to nozzle dynamic pressure vs. the ratio of standoff distance to nozzle diameter. 50.8 mm porous tube.

ANALYSIS OF RESULTS

The present observations of the structure and nature of the pressure signal for both the confined and unconfined jets are in agreement with those of other investigators (see, for example, references 7 and 8). Where the present work differs from these previous researchers is in the analysis of the data. In the past attention has been focused upon either average pressures or upon peak values. It is the contention here that neither of these quantities describes the jet behaviour adequately to develop a model to predict cutting rates. Instead it is proposed that because of the unsteady nature of the pressure it is more appropriate to characterize the signal by a statistical approach, hence the emphasis upon measuring probability distributions. In the following section these distributions will be incorporated into a jet piercing model, i.e. a procedure for predicting maximum depths of penetration and cutting rates.

Maximum Depth of Penetration

In order to estimate the maximum penetration of the jet, it is first assumed that the pressure at the working face (p) must exceed some critical value (p_c) before cutting can occur. The maximum depth of penetration could be specified by comparing either the average or the peak pressure to this critical value. In view of the present findings, neither seems apprioriate. If the average pressure falls below p_c, a portion of the pressure signal will be above p_c and cutting may continue for some fraction of time. Use of peak pressures is also not convenient because cutting will depend upon the frequency of peak excursions above p_c. Instead, the approach here is to determine for each standoff distance and set of jet parameters the probability that the critical pressure is exceeded, $P[p > p_c]$. This probability is the area under the PDF curve to the right of $p = p_c$, as illustrated in Figure 8a, and is most easily determined from the CDF curve as shown in Figure 8b. The probability that $p > p_c$ decreases with increasing standoff distance as shown by the CDF's in Figure 8c for a given set of jetting parameters. Plots of $P[p > p_c]$ against standoff distance for various nozzle pressures are shown in Figure 9 for a 1.6 mm diameter nozzle and 50.8 mm diameter tube.

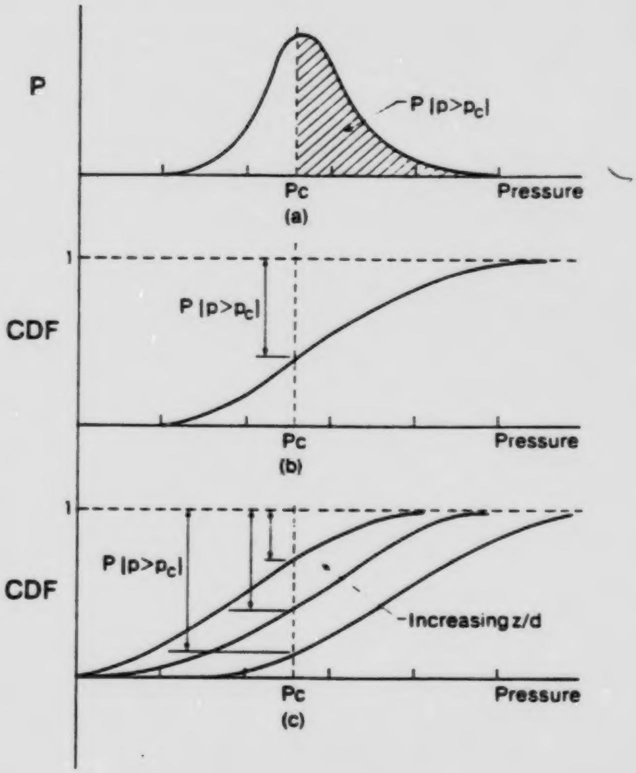

Fig. 8. Examples of a) PDF and b) CDF, demonstrating the evaluation of the probability that the pressure exceeds the critical value $P[p > p_c]$. In (c) the influence of the standoff distance upon this probability is illustrated.

To obtain each curve like those in Fig. 9, a value for the critical pressure p_c had to be determined. Unfortunately, because of the spatial averaging of the signal the measured peak pressures are substantially lower than actual peak values. This is evidenced by observations of damage to the surface of the transducer at small standoff distances (which would require local stresses at least equal to the yield strength of steel) when the indicated peak pressures were only about 500 kPa. Consequently there is the problem of relating the measured signal to the actual value of the critical pressure. In an attempt to accomplish this, reference was made to some previous laboratory tests (5) where it was found that a nozzle pressure of 1.2 MPa would not produce failure at an oil sands surface at a standoff of 125 nozzle diameters. These conditions were reproduced (including the same nozzle) with the current apparatus

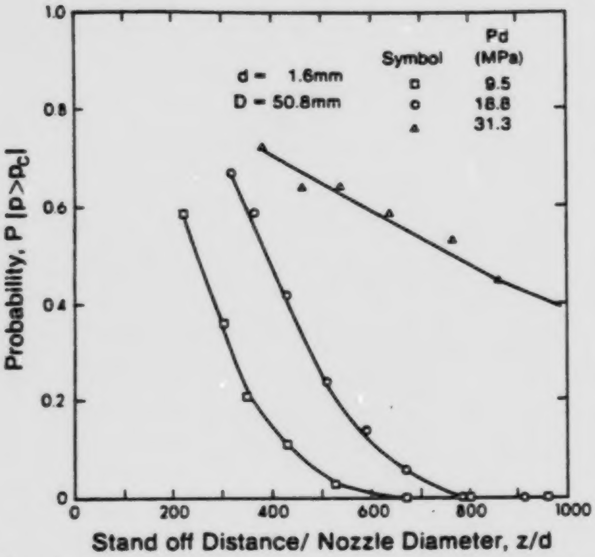

Fig. 9. The probability that the pressure exceeds the critical value versus non-dimensionalized standoff distance for a given set of jet parameters.

and a PDF and CDF were obtained. To specify a value for p_c, an assumption was made that no penetration occurs when the probability that $p > p_c$ falls below a certain value, P*. Here it is assumed that $P^* = 0.05$. This is somewhat arbitrary, but as shall be seen later, the results are somewhat insensitive to the value of P*. With $P^* = 0.05$ then, a value for $p_c = 70$ kPa was determined from the CDF.

A curve of the form

$$P[p > p_c] = e^{-\lambda(\frac{z}{d})^2}$$

has been fitted to each set of data like those shown in Fig. 9, thus obtaining values for the jetting parameter λ for each set of test parameters.

The parameter λ could be a function of at least the nozzle diameter, pressure and the tube diameter. As shown in Figure 10, however, over the range of variables tested, λ is only a strong function of the jet dynamic pressure. The assumed form of this relationship is

$$\lambda = \frac{A}{P_d^B}$$

with P_d expressed in MPa. Values for $A = 1.1 \times 10^{-4}$ and $B \cong 1.1$ were determined by a least square fit. The fitted curve is also shown in Fig. 10.

The expression for the probability that $p > p_c$ is then

$$P[p > p_c] = e^{-\frac{1.1 \times 10^{-4}}{P_d^{1.1}}(\frac{z}{d})^2}$$

For any given nozzle pressure and diameter, this expression yields the maximum expected penetration corresponding to the assumed limiting value P*. For $P^* = 0.05$, the expected maximum penetration is

$$(\frac{z}{d})_{max} \doteq 165\, P_c^{.55},\ P_d \text{ in MPa}$$

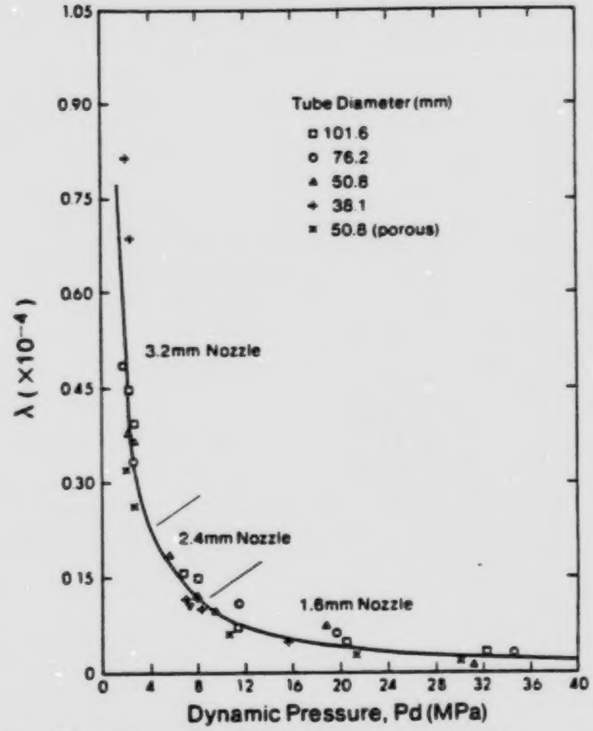

Fig. 10. The jetting parameter λ as a function of dynamic pressure for different nozzles and tube sizes.

Rate of Penetration

In addition to predicting the maximum depth of penetration it is also very desirable to be able to estimate the time required to penetrate to that depth. An operator running a down-hole jet piercing test then only has to jet for a predetermined time interval. An estimate for this time may be made by assuming a relation between the instantaneous cutting rate, $\frac{dz}{dt}$, and the probability that the critical pressure p_c is exceeded. The simplest possible relation is linear, i.e

$$\frac{dz}{dt} = K\, P[p > p_c]$$

The constant "K", which may depend on nozzle diameter and pressure, is interpreted as the initial cutting rate (mm/sec) since for small standoff distances the probability $P[p > p_c] \doteq 1$. This relation assumes that the cutting rate is independent of the magnitude of p at the cutting face as long as it exceeds p_c. The present simple relation was assumed because the data available to determine the constants in such a relation are limited. The expression for the cutting rate now becomes

$$\frac{d(\frac{z}{d})}{dt} = \frac{K}{d} e^{-\lambda(\frac{z}{d})^2}$$

which may be integrated to give the time required to reach a given depth as

$$t = \frac{d}{k} \int_0^{z/d} e^{+\lambda(\frac{z}{d})^2} d(\frac{z}{d})$$

TABLE 1

P_d(MPa)	K(mm/sec)
12	41.6
17	56.0
23	68.8
25	73.6
36	81.6

In order to determine the cutting time, (assuming $\frac{z}{d} = 0$ at $t = 0$) the initial cutting rate K must be known. Some limited information is available for depths of penetration versus time for a 1.6 mm nozzle at a 200 mm standoff for several nozzle pressures (5). From these data, values of K were determined by fitting the predictions of equation (1) to the data, and are summarized in Table 1.

DISCUSSION OF RESULTS

The predictions for the depth of penetration with time have been plotted in Figures 11 and 12 for a 6.4 mm diameter nozzle and three nozzle pressures. In Fig. 11 the time axis has been extended only to 100 seconds for better comparison with the field data (5). It is not possible to draw any strong conclusions from the figure because of the limited field data, and a maximum jetting time in the field of only 60 seconds.

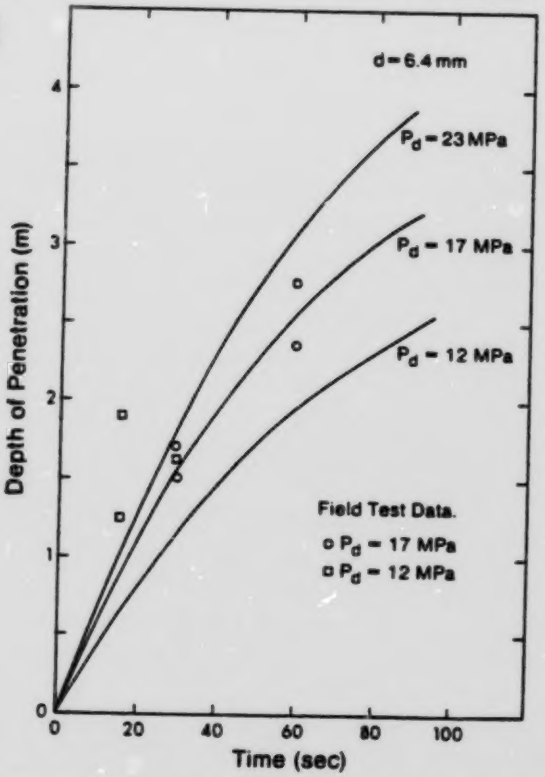

Fig. 11. A comparison of the predicted and actual depths of penetration into oil sands for a 6.4 mm diameter nozzle for several dynamic pressures and jetting times.

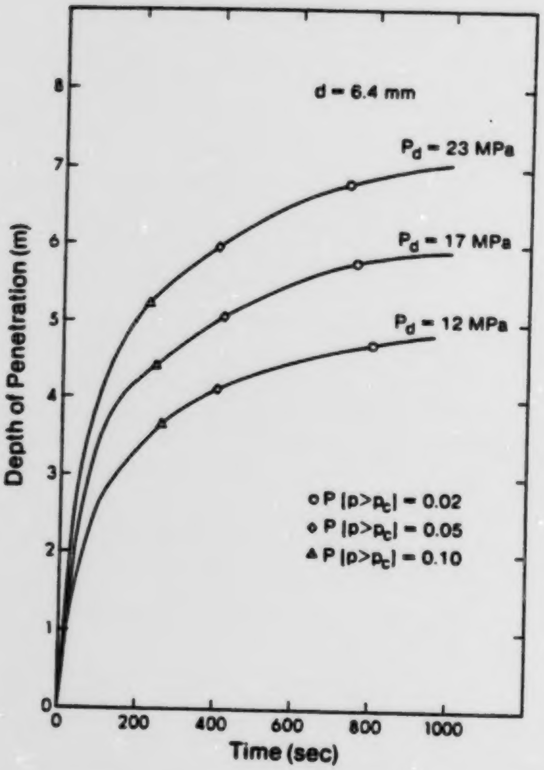

Fig. 12. Predictions of the maximum depth of penetration for a 6.4 mm diameter nozzle and the time to reach that depth for several cutting criteria and nozzle pressures.

An implicit assumption in the analysis is that the oil sands are homogeneous. Some of the scatter in the field data is due to the fact that at the field test site, the oil sand formation is stratified. Depending on the angle of incidence of the jet to the strata, the penetration varied accordingly.

In figure 12, the time axis has been extended to show predicted maximum depths of penetration, using three values of P*. Over the range $0.02 < P^* < 0.10$ the predicted maximum depth changes by about 20 percent. Since the scatter in the field data can easily approach this value, a value for P* of 0.05 seems a reasonable compromise. For a 6.4 mm diameter nozzle, the correlation predicts a maximum penetration of about 6 m in 400 seconds for a jet pressure of 23 MPa. Continued jetting beyond this time becomes rapidly less productive, even with the implicit assumption that the jet does not become submerged due to build up of water in the well bore.

In deriving the curves of Figs. 11 and 12 it was assumed that the rate of penetration is related to the probability that some critical pressure is exceeded. This assumption means that the penetration rate is independent of the pressure provided that it exceeds the critical value. It is unlikely that this is true, and has only been done here because the limited data available did not warrant a more complex model. The correlation should at least include a second term which is related to the expected value of the pressure, and consequently would introduce a dependence upon magnitude by which the critical value is exceeded.

It is also to be noted that the correlation is independent of the horizontal tube size. One of the original intentions of the study was to investigate the influence of confining the jet upon the pressure decay with distance. For the range of variables chosen here there appears to be no effect except for the smallest tube when slugs began to form. Assuming the smallest tube is the corresponding value for the actual conditions, it is still unknown whether a slug will form or not, due to the porosity of the oil sands formation. As observed during the field tests (5), water returned through previously drilled holes as far as 2 meters away. Consequently the assumption of a solid wall is probably too severe and use of the pressure decay for the essentially unconfined jets appears to be a reasonable approach.

CONCLUSION

The characteristics of the flow in a high pressure water jet directed into a closed horizontal tube have been examined qualitatively and quantitatively. Observation of the discrete nature of the jet structure has led to the conclusion that a statistical approach to analyzing the pressure signal is necessary. Rather than considering average or peak pressure values, the analysis is based on the probability that the pressure will exceed some critical value. This results in a correlation which provides estimates of the maximum expected penetration as a function of jet dynamic pressure and nozzle diameter. Furthermore, by assuming a relation between this probability and the cutting rate, an estimate of the time required to reach maximum penetration may be made.

The agreement between the correlation and the field data is reasonable, however the field data is too sparse for a valid comparison. One addition to the correlation which would make it more realistic is to modify the assumed relation for the cutting rate to include the effect of the magnitude of the pressure above the cutting threshold.

The use of a solid wall tube to model the hole appears to be too severe, and a porous wall more realistic. However, further evaluation of the experimental geometry and the proposed cutting correlation requires significantly more field and experimental data.

ACKNOWLEDGEMENT

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(34)

TEDSI develops horizontal drilling technology

Anthony W. Gorody
Texas Eastern Drilling Systems Inc.
Houston

During the past several years, Texas Eastern Drilling Systems Inc. (TEDSI), a wholly owned subsidiary of Texas Eastern Corp., has refined a drilling system for lateral borehole completions. The system, now being used by major operators, is being made available under the supervision of TEDSI crews through a choice of contracts under conventional commercial terms.

The performance constraints of similar but older technology, such as that developed by John A. Zublin in 1929, have been overcome. Higher material strengths and a modernized design have yielded a reliable, durable drilling system that is compatible with conventional rotary rig equipment.

The system can be directed from a vertical wellbore toward a horizontal attitude through a curve of short radius. Orientation can be set, maintained, or adjusted during drainhole drilling. Several drainholes at one or more horizons can be drilled from a single wellbore, allowing completion of more than one formation.

Drainhole lengths of 200 to 400 ft beyond the vertical wellbore are typical, although 700-ft reach has been attained.

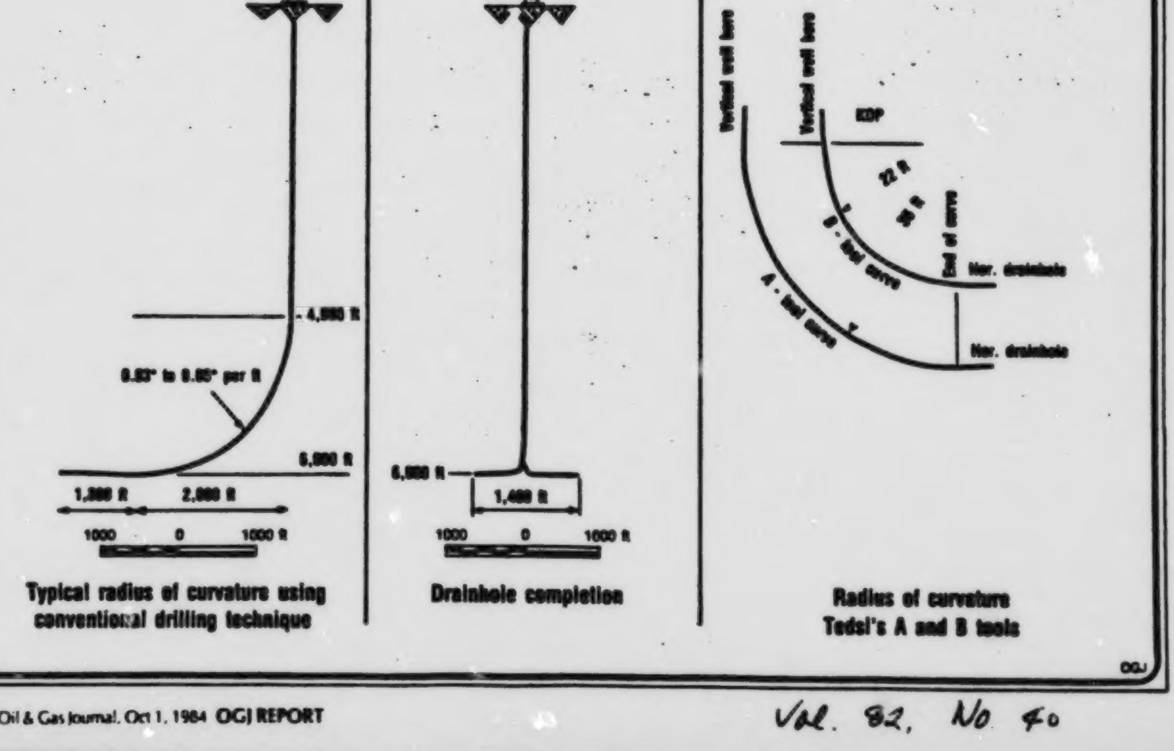
During TEDSI's development and applications testing, over 150 drainholes were completed for a combined length exceeding 35,000 ft. Many kinds of lithologies were successfully drilled, including indurated sandstones and siltstones, limestones, chalks, dolomites, calcareous shales, siliceous shales, cherts, and evaporites.

Based on available published information, TEDSI's proprietary stabilization and short radius capability, combined with the ability to drill significantly extended and controlled laterals, sets this drilling system apart from other horizontal completion methods.

Drilling assembly. TEDSI's drilling system uses a flexible string assembly available in two diameters, 3¾ and 4½ in., which permit entry into any borehole with a diameter of at least 4¾ in. Each flexible string can be equipped with two separate bottom hole assemblies: one for drilling the curved portion of the hole, the other for completing the lateral portion.

Drainhole drilling comparison

Fig. 1



Typical radius of curvature using conventional drilling technique

Drainhole completion

Radius of curvature
Tedsi's A and B tools

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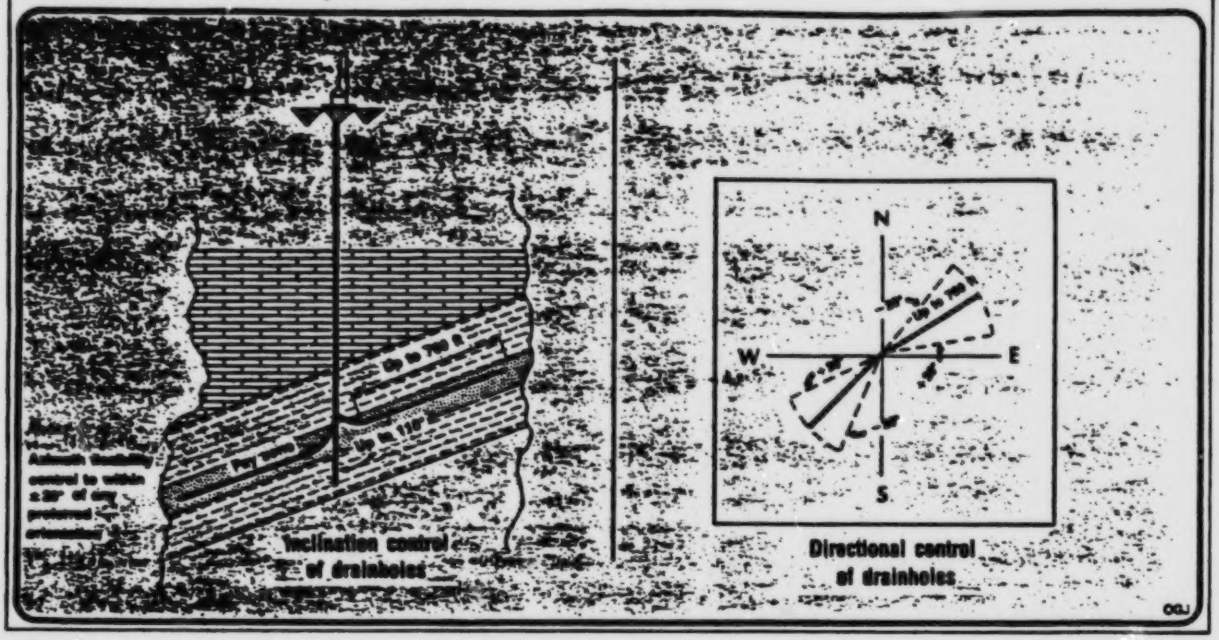
Fig. 2

Drainhole control parameters


Up to 700 ft
Pay zone
Up to 110°
Inclination control of drainholes
N
W
E
S
Up to 700 ft
Directional control of drainholes
OGJ

Bottom-hole assemblies are mounted with the bit most compatible with the type of formation being drilled. Bit rotation is conventionally powered from the surface and any conventional drilling fluid medium, including air, can be circulated. No special additives or extra fluids are required.

Because internal flow passage diameters range from 1 to 1½ in., both tools are capable of handling normal drilling fluid volumes at pressure drops across the bottom hole assembly up to 1,000 psi. Normal drilling parameters might be 8-10,000 lb weight on bit at 60 rpm.

The smaller diameter curve-drilling bottom hole assembly will drill a 20-ft radius of curvature; the large diameter assembly, a 35-ft radius of curvature (Fig. 1). Both lateral borehole cutting tools will drill a straight hole that maintains the attitude reached at the end of the curve. This attitude can be preset at any angle from vertical to up to 20° above the horizontal plane and to within an accuracy of 5° (less if required). The azimuth, or direction, of the lateral borehole can be controlled to within 20° of target (Fig. 2).

In favorable reservoir conditions, TEDSI has drilled laterals to 700 ft from the vertical wellbore. Greater lengths could have been attained had they been required. Although this drilling system has not yet been used at depths greater than 10,000 ft, it can operate without modification to its present design at any depth provided bottom hole temperatures do not exceed 250° F.

Drainhole drilling. A typical completion requires a two-or-three-man TEDSI crew with a set of drilling tools, bottom hole surveying instruments appropriate for the specific job, and mud-logging equipment as needed. The TEDSI team uses the operator's standard drilling or workover rig and directs the regular crew. To protect proprietary details of tool construction and operation, TEDSI does not allow observers.

In open hole intervals, a drainhole can be oriented as required and drilled directly off bottom or from anywhere throughout the interval. In cased intervals, a window is cut above the completion zone, and the drainhole is drilled through the window.

In the most commonly encountered situation, casing extends to a point directly above the zone of interest, and the target zone or zones lie within the open hole interval below the casing.

The open hole is logged and kickoff point(s) selected. Where orientation is required, a retrievable orienting device is lowered, usually to the deepest target zone first.

Conventional instrumentation is used to orient the device, which is then locked into place.

After two-thirds of the curve is drilled with the curve-cutting bottom hole assembly, the hole is surveyed with a multishot camera lowered on a drillstring to confirm proper orientation. Azimuthal adjustment can be made, if necessary, while the final third of the curve is drilled. A second similar survey may be made after the curve is completed, but this is normally not required.

The second bottom hole assembly is then lowered through the completed curve, and the lateral portion of the drainhole completion is drilled until the target is reached or the bit wears out. The hole can be surveyed again before re-entering with a new bit, or it can be surveyed at the end of the completed lateral.

Two typical surveys are documented in Fig. 3. Once all drilling requirements have been met, the orienting device is released and retrieved for the next required drainhole orientation. Where necessary, a slotted liner can be installed in the drainhole.

Grassy Trails field. TEDSI successfully demonstrated the system's operating capabilities in the Triassic Moenkopi reservoir in Grassy Trails field, Emery Co., Utah. Multiple zone completions in low permeability, fractured reservoirs were carried out for the Skyline Oil Co., a subsidiary of Texas Eastern Corp.

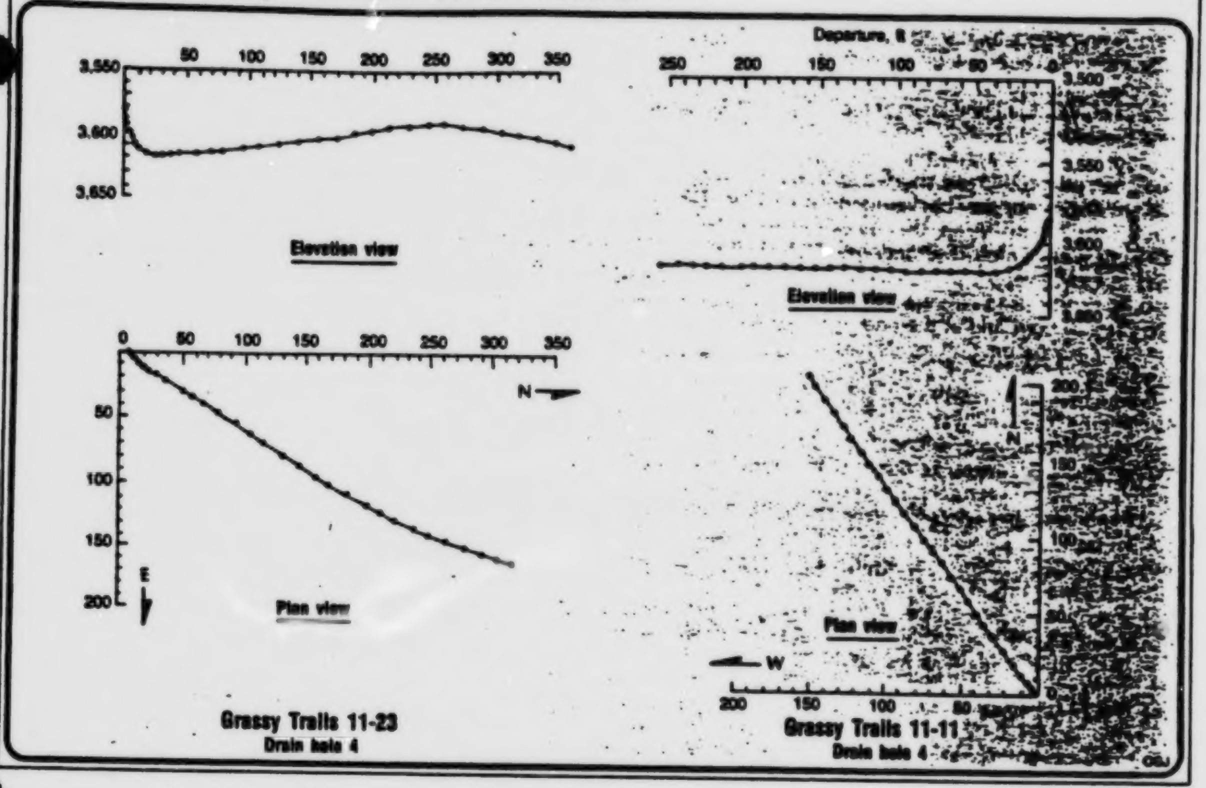
Two extremely tight (0.01 md and 4-5% porosity) siltstone beds, each varying in thickness from 10 to 60 ft, were the targets for the drainholes.

Total length of 68 drainholes drilled from 18 wellbores was approximately 17,000 ft, for an average length of about 250 ft per drainhole. Both size tools were used to drill laterals that were, generally, at 85° or 90° to the vertical wellbore.

Four of eleven exploration wells

Surveys show positive direction control

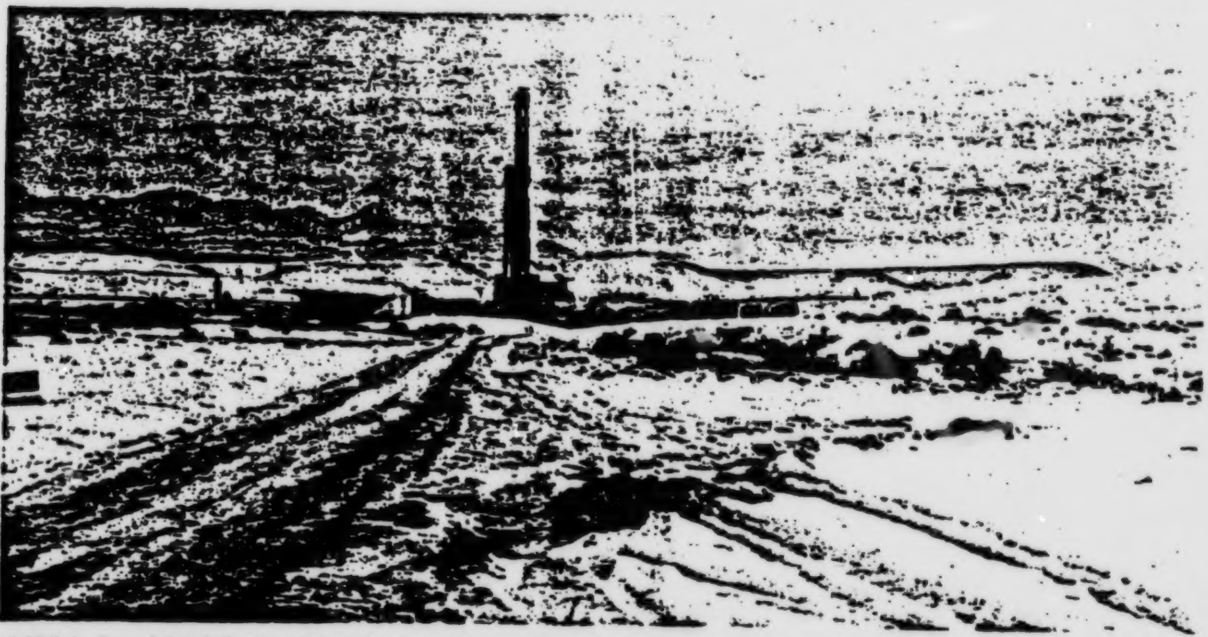
Fig. 3



were producers. Of the seven dry exploration wells, 3 were distant stepouts, one was downdip, and 3 were updip of a "sweet" spot that was discovered and subsequently developed.

Six of seven subsequent development wells were significant producers, yet nearly all of them were dry before drilling multiple laterals.

Well GT 11-33X. One of the better wells in this field was well 11-33X. Drilled with air to a vertical depth of 3,906 ft, the 4¾-in. borehole was dry and without any show of oil. The first drainhole, drilled from 3,443 ft, was 220 ft long, and intersected major multiple fractures spaced approxi-



Multiple horizontal drainholes turned dry holes into producers at Grassy Trails, Utah. An average of 3.7, 250-ft laterals per well intersect fractures to overcome permeability restrictions (Fig. 4).

mately 70 ft apart.

As each fracture was approached, torque became erratic and the drilling rate slowed dramatically. Normal drilling conditions resumed as each fracture was completely crossed, and a surge of oil would fill the tanks at the end of the blooie line.

As additional fractures were intersected, net oil production increased while drilling, and the background gas readings recorded on the mud logger's chromatograph rose and stabilized at new levels.

Initial production levels were gauged at 220 bo/d and at the end of 323 days, daily production levels had decreased to 70 bo/d with cummulative production totalling 39,000 bbl.

At that time, the well was reentered and a second drainhole drilled from 3,451 ft at a 55° angle to the first drainhole. This new drainhole intersected major fractures spaced approximately every 35 ft along a lateral distance of 476 ft from the vertical wellbore. Initial production was reestablished at a renewed rate of 280 bo/d, and the well has produced an additional 35,000 bbl in a 153 day period following recompletion.

The TEDSI system has been mechanically successful in numerous drilling programs, but the experience at Grassy Trails established the system as a viable completion technique for commercial field development.

Cost. The cost of drainhole completions is primarily a function of time, which varies with the complexity of completion and field operating conditions. Deep target zones, cased target zones, hard formations, degree of precision in orienting the drainholes, and number of drainholes drilled all contribute to the total cost of a completion service. A reliable estimate for a single or multiple drainhole program can be calculated based upon these factors.

The cost of completion will range between $50,000 and $150,000 per lateral including rig and associated equipment.

Drainhole completion vs. other completion technologies. Drainhole completion technology, as improved, occupies a unique niche in the completions industry. No other single technique provides as many potential means for enhancing resource recovery or rate of production.

Drainhole completions can potentially:

- Extend direct contact with a producing formation to: increase net pay; create a high permeability streak in a tight formation; extend access to a formation sensitive to frac fluids; and reach narrowly missed exploration targets.
- Replace radial drainage toward a vertical wellbore with linear drainage along the length of the lateral for: higher rate of production; maximum ultimate recovery; and enhanced injectively and improved sweep efficiency in EOR programs.
- Reduce the pressure gradient at the vertical wellbore to conserve reservoir energy and minimize fluid coning.
- Cross numerous naturally occuring vertical fractures to: increase the success ratio of producing to nonproducing wells in fractured reservoirs and reach for fractures in directions independent of the local stress regime.
- Readily sample reservoirs with laterally non-homogeneous lithologies.

The current TEDSI drainhole drilling system opens the door to these benefits.

Further refinements to equipment, designed to minimize rig time and overall cost, are under current development. Standard equipment seals and lubricants are being modified to withstand higher bottom-hole temperatures, and a new type of downhole motor is being developed. A small articulated gyroscopic probe and inclinometer that can be wirelined through the flexible drillstring as it relays its downhole position to a surface computer is nearly ready for commercial use.

With the system's present state of proven mechanical reliability and further refinements in the works, TEDSI anticipates that use of its drainhole completion technology will become a common practice.

The author...

Gorody

Tony Gorody is research advisor, TEDSI, Houston. He has been involved with the development of several of the techniques for horizontal drilling and recommends applications. He joined TEDSI in 1982 after 2 years as a geologist with Texas Eastern. Gorody earned a BS from Rutgers and MS and PhD degrees in geology from Rice.

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THE USE OF HORIZONTAL DRAINHOLES IN THE EMPIRE ABO UNIT

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by Ryan L. Stramp, ARCO Oil and Gas Co.

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ABSTRACT

ARCO Oil and Gas Company has drilled two horizontal drainhole wells in the Empire Abo Unit. A horizontal drainhole well is one in which the wellbore is turned from vertical to horizontal in a short radius and the horizontal hole is then drilled out some distance into the formation. These wells were drilled to aluate the mechanical feasibility of drilling process and to examine the fect producing through the drainholes would have on the well's tendencies to form gas cones. Although several problems were encountered while drilling the drainholes, the drilling technique used does seem to be mechanically sound. The wells have not been on production long enough to fully evaluate their gas coning performance as compared to conventionally completed wells.

This paper will briefly examine the gas coning problem in the Empire Abo Unit, discuss some of the techniques used to limit gas coning in the Unit, and review ARCO's experience with horizontal drainholes.

INTRODUCTION

ARCO Oil and Gas Company operates the Empire Abo Unit, located in the Empire Abo Pool of Eddy County, New Mexico (Figure 1). The Unit consists of approximately 11,000 acres and represents about 97% of the entire pool.

Production is from the Permian (Lower Leonard) Abo Reef dolomite at a depth of approximately 6200'. The pro- tive reef development is approximate- 12.5 miles long and 1.5 miles wide (Figure 2). The cross-sectional view in Figure 3 illustrates the massive reef development. The main producing mechanism is gravity drainage which is now supplemented by the injection of the residue gas into the gas cap.

The pool was discovered in 1957. Competitive development of the field on 40-acre spacing was rapid. The pool was operated on a competitive basis until 1973 at which time the Empire Abo Unit was formed. S. H. Christianson's paper[1] gives a detailed description of the reservoir and discusses factors involved in the formation of the Unit.

Prior to unitization, approximately 96 MMBO were produced from the Abo Reef. An additional 91 MMBO have been produced from the date of unitization through April, 1980. The Unit's current production rate is about 25,000 BOPD.

GAS CONING IN THE UNIT

At the time of discovery, the Abo reservoir pressure was above the crude's bubble point. Competitive production of the pool resulted in a drop in pressure to below the bubble point and the formation of a secondary gas cap. By the early 1970's several wells in the up-dip area of the pool began to produce at gas/oil ratios (GOR's) in excess of the solution GOR indicating the production of free gas from the gas cap. Drill stem test information indicated that these high GOR wells were perforated below the level of the regional gas/oil contact. Localized depressions in the gas/oil contact around the wellbores (gas cones) were causing the high GOR production.

Producing Empire Abo wells at high GOR's is undesirable for two reasons. First, free gas production rapidly de-

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References and illustrations at end of paper.

pletes the reservoir pressure resulting in reduced ultimate recovery. The second problem with high GOR production is illustrated by Figure 4. Due to the relative permeability characteristics of the Abo reservoir, a well's oil production rate drops sharply when it begins to produce at GOR's in excess of the solution GOR (currently about 700 CF/BO).

After unitization, the high GOR wells were shut-in and their allowables were transferred to low GOR producers with excess producing capacity.

There are no longer any Unit wells with excess capacity that can be used to replace the lost oil rate that occurs when wells begin to produce at high GOR's. For this reason, gas coning has become the most serious operating problem facing the Unit owners. Several methods for controlling the problem have been explored.

Many of the older wells in the Unit were originally completed high in the pay. In this instance, the most effective way to reduce a well's GOR when it begins to cone gas is by squeeze cementing the perforations and recompleting lower in the reef. Most of the wells in the Unit are now completed as low in the reef as possible; therefore, very few of these opportunities remain.

The drilling of 158 infill wells in the Unit during the late 1970's was an indirect means of reducing the gas coning problem. Computer modeling indicated that reducing the well spacing from 40 acres to 10 acres in selected areas of the Unit would result in the recovery of additional reserves. With the additional wells, the oil withdrawals from the reservoir were dispersed while maintaining the overall producing rate. This resulted in a reduction of individual well oil producing rates, thereby reducing gas coning tendencies and increasing ultimate recovery.

As the gas coning problem in the Unit became more severe, ARCO began investigating less conventional means of controlling the problem. Production from horizontal drainholes was one of the alternatives evaluated.

THE DRILLING OF HORIZONTAL DRAINHOLES

The concept of horizontal drainhole drilling is not new. Drainhole drilling technology was actually developed in the 1950's[2,3,4]. With the exception of a few isolated tests, however, the process has not been used in the petroleum industry.

ARCO contacted an outside drainhole drilling consultant who had equipment for drilling drainholes of up to 200' in length with a turn radius of less than 30 feet. A short radius turn is critical to the successful use of drainholes to limit coning.

The sharp turn is accomplished by using a whipstock, flexible drill collars, and a specially designed angle building bottom hole assembly.

Figure 5 illustrates the design of the flexible drill collars. The jig-saw puzzle cut through standard drill collar stock provides for the flexibility. A 1-inch I.D. high pressure rubber hose runs through the center of each collar to transport mud to the bit. Each drill collar is 10 feet long and is jointed on 11-inch centers.

The angle building bottom hole assembly consists of a 4-3/4 inch three cone bit and a 4-inch OD knuckle joint. Below the knuckle joint is a 1/16-inch over gauge stabilizer (Figure 5).

The turn is initiated with the angle building assembly drilling off the whipstock. Once clear of the whipstock, the weight on the knuckle joint continues the turn. When the turn to horizontal is nearly complete, the knuckle joint is removed and additional stabilization is added, resulting in a stabilized bottomhole assembly with no angle building tendencies. The remainder of the drainhole is drilled with this assembly.

SURVEYS

Taking directional surveys in drainholes also requires special equipment. A 120° Eastman Whipstock Type A single shot, survey unit is used. A monel sucker rod is run directly above the survey unit, and several standard sucker rods are run above the monel rod. This assembly is run in the hole on a wire line. The weight of the sucker rods pushes the survey unit to the end of the drainhole.

Surveys are taken frequently during the drilling of the drainhole. The small I.D. of the hoses in the flexible drill collars necessitates pulling the drillstring to take surveys. Although this makes directional surveying quite time consuming, frequent surveys are necessary to monitor the course of the drainhole.

COST

The estimated total cost to drill and complete a Unit well with a horizontal drainhole completion is about $500,000. This is approximately double the cost of a conventionally completed well in the Unit.

APPLICATION OF DRAINHOLES IN THE EMPIRE ABO UNIT

ARCO's Research and Development Group in Plano, Texas conducted a numeric model study comparing horizontal drainhole completions to conventional completions in the Unit. Their study showed that a drainhole would indeed recover more oil reserves than a conventionally completed well.

Figure 6 shows how a typical conventional Abo well is completed. The well is drilled through the base of the Abo Reef, and casing is set and cemented. A porosity zone, as near the base of the reef as possible, is selected and perforated. The zone is then stimulated with a density controlled acid treatment. This technique consists of pumping pads of lease crude and calcium chloride water ahead of the acid. The acid's density is between the densities of the two pads. The density differences help to keep the treatment confined vertically. Even with this density controlled procedure, significant upward etching often occurs making the acidized well even more susceptible to gas coning than a non-acidized completion. The pressure gradient between the uppermost end of the treated interval and the gas cap is the driving force which causes the gas cone to form.

Figure 7 illustrates an ideal horizontal drainhole completion in the Abo Reef. The key to the reduced gas coning tendency of the drainhole is the large drainhole surface area open to flow. A simple application of Darcy's law indicates that for the same production rate, the required pressure drop into the wellbore is many times less for the 200' drainhole completion than for the 20' conventional completion. This reduction in pressure gradient reduces the drainhole's susceptibility to gas coning.

Figure 8 shows the cumulative oil production versus time results from the model study for a 200' horizontal drainhole and for a conventionally completed well. The model study indicated that a drainhole completion would recover approximately 30 MBO more than the conventional completion.

Based on these results, the Unit working interest owners decided to drill a well to test the mechanical feasibility of the drainhole drilling technique and to check performance characteristics of the drainhole. Unit well K-142 was selected to be the first test well (Figure 2).

DRAINHOLE DRILLING PLAN

The K-142 was spudded in July, 1979. The well plan for the K-142 included setting 11" surface casing at 1000' then drilling an 8-3/4" hole to 5900'. Hole size was then reduced to 6" and drilling continued to 6150'. At this point, open hole porosity and resistivity logs were run. A drainhole target depth of 6047' was selected based on porosity development.

Straddle packer drill stem tests located the gas/oil contact at approximately 5900'. The 6" hole was opened to 8-3/4" from 5900' to 6016'. Seven inch casing was run and cemented at 6016'. The hole size changes were necessary because the setting depth for the 7" casing was dependent on the exact drainhole target depth, and the drainhole tools are designed to kick-off out of a 6" hole.

The whipstock was run in the hole and oriented in a S-20°E direction. This direction was selected to ensure that the drainhole intersected the reef's major fracture trend at right angles.

The flexible drill collars and angle building bottom hole assembly were run in the hole, and drainhole drilling began.

After 7' of drainhole had been drilled, a drill pipe connection was necessary. Following the connection, the drillstring would not go back to bottom. It stopped at the depth of the whipstock, indicating either a collapse of the drainhole or a rotation of the whipstock. Later evidence indicated that the whipstock had turned.

Drainhole drilling operations resumed. After 19' of hole had been drilled in the second drainhole, a directional survey was run. The drift direction indicated that the whipstock had indeed rotated. Another 24' was drilled in drainhole No. 2 before the next survey was taken. The survey tool would only go 7' below the depth of the whipstock, and the drift direction corresponded to the original orientation of the whipstock. Evidently the whipstock had rotated during the pipe trip; returning to its original orientation.

The drilling operations continued in Drainhole No. 1. The turn from vertical to horizontal was accomplished after a total of approximately 35 feet of drainhole had been drilled. This corresponds to a turn radius of about 28 feet.

Once horizontal, the hole began climbing and corkscrewing to the left. After a total of 106' had been drilled in Drainhole No. 1, the drainhole drilling operations were halted due to increased torque on the drillstring in the corkscrewed hole.

Figure 9 is an isometric drawing of the results of the K-142 drainhole drilling.

COMPLETION OF THE K-142

The completion process began with displacing the drilling fluid from the hole with potassium chloride water. The well was then swabbed for several days resulting in little recovery. Next, coiled tubing was run into drainhole No. 1, and approximately 35 MCF of nitrogen was injected in an attempt to clean out any drilling fluid remaining in the drainhole.

Following the nitrogen treatment, the well began flowing intermittently into the test tank. After a few days, the well was flowing at a rate of about 200 BOPD into the tank; however, the flowing tubing pressure was not sufficient to produce into the Unit's production system.

A hydraulic jet pump was installed on the K-142, and in mid-October, 1979, the well was potentialed at 200 BOPD at a GOR of 670 CF/BO. This rate and GOR are similar to conventionally completed wells in the area. The K-142 has continued to produce at 200 BOPD at GOR's less than 1000 CF/BO. Through April 30, 1980, the well has produced approximately 36 MBO. An important point to note is that the K-142 was never acidized. All of the conventionally completed wells in the area required acid treatments prior to production.

ANALYSIS OF DRILLING PROBLEMS ENCOUNTERED

The two major problems encountered while drilling the K-142 (whipstock rotation and inadequate stabilization) were studied and actions were taken to eliminate these problems prior to the drilling of the second drainhole well in the Unit. The whipstock used in the K-142 relied solely on a spade on the bottom of the tailpipe to maintain its orientation. Any combination of upward force and twisting movement tended to displace the whipstock from its original direction. Residual torque in the drill pipe during a pipe connection and a pipe trip resulted in the two rotations of the whipstock during the drilling of K-142. A whipstock with a positive mechanical holddown was used in the second drainhole well, and it performed satisfactorily.

The corkscrewing of the hole was attributed to a flaw in the design of the stabilizing bottom hole assembly. The design was modified resulting in much better control while drilling the second well.

DRILLING THE SECOND DRAINHOLE WELL

Based on the results of the drilling of the K-142, the Unit owners spudded the Empire Abo Unit J-213 in March, 1980 as a second drainhole test (Figure 2).

The first drainhole well was primarily a mechanical test of the drainhole drilling technique. The location of the K-142 was selected in an area of the Unit that contains several low GOR producing wells. This was done so that an economic conventional completion would be possible if the drainhole could not be drilled.

The J-213 location, however, is in an area containing only high GOR wells. Conventional infill wells in this area have produced at low GOR's for only short periods of time before coning gas. This location is a more rigorous test of the use of drainholes in the Unit to reduce gas coning.

The drilling plan for the J-213 was substantially the same as that of the K-142. After the vertical hole had been drilled to 6225', drill stem tests located the gas/oil contact at about 6070'. A drainhole target depth of 6137' was selected from the open hole logs.

The whipstock was set at 6115' and oriented in a westerly direction. One major difference between this well and the K-142 was that the drilling rig was used to drill the K-142 drainholes, and a pulling unit with power swivel was selected to drill the J-213 drainhole. This change in procedure was implemented to reduce the cost of the J-213.

Drainhole drilling began and initially progressed quite smoothly. The turn from vertical to horizontal was completed in 46 feet and a radius of about 26 feet. At that point,however, as happened on the first well, the drainhole started to climb. Several attempts were made to drop the angle back to 90°, but none succeeded. After a total of 127 feet of drainhole had been drilled in the J-213, drilling operations were suspended. The drainhole had climbed to 6125', and it was decided to stop the drilling, rather than have the drainhole climb any closer to the gas/oil contact. Figure 10 shows the path of the J-213 drainhole.

The problem of the hole climbing resulted from drilling with the angle building bottom hole assembly for too long. It is evident that the timing of the changeover to the stabilized bottom hole assembly is critical to the drilling of a truly horizontal hole.

The drilling of the J-213 drainhole was finished in late May, and no completion results are available as yet. The completion procedure used in the J-213 will be similar to the K-142 completion procedure.

FUTURE PLANS FOR DRAINHOLES AT EMPIRE

At the time of this writing, the future of drainhole drilling in the Empire Abo Unit is uncertain. Although problems were encountered resulting in premature termination of the drainhole drilling on the first two wells, the basic process seems to be sound.

The question that remains to be answered is whether drainhole completions are less susceptible to gas coning than conventional completions. The K-142 continues to produce at low GOR's; however, there are also low GOR conventionally completed wells in its vicinity. This fact makes analyzing the effect of K-142 drainhole completion difficult.

The Unit owners will closely observe the GOR performance of the J-213. If the results are encouraging, we will probably continue the drainhole drilling program. If the J-213 produces at high GOR's, we will have to re-examine our analysis and decide whether or not further experimentation is justified.

CONCLUSIONS

1. Numeric modeling indicates that producing through a horizontal drainhole completion will result in increased oil recovery as compared to a conventionally completed Empire Abo well.

2. The drainhole drilling process was found to be mechanically feasible, even though problems were encountered during the drilling of the first two drainhole wells in the Empire Abo Unit.

3. Horizontal drainhole wells can be successfully completed in the Empire Abo Unit.

4. The full effect that producing through horizontal drainholes will have on gas coning tendencies has not yet been evaluated.

NOMENCLATURE

CF - cubic feet of gas
BO - barrels of oil
BOPD - barrels of oil per day
GOR - gas/oil ratio
ID - inside diameter
MBO - thousand barrels of oil
MMBO - million barrels of oil
MCF - thousand cubic feet
OD - outside diameter

ACKNOWLEDGEMENTS

I would like to thank the management of ARCO Oil and Gas Company and the other Unit owners for permission to present this paper. In addition, Mr. Leroy Lane, West Permian Drilling Supervisor with ARCO, and Mr. Don Holbert of Don Holbert - Drainholes, Inc., were of great assistance in the preparation of the paper.

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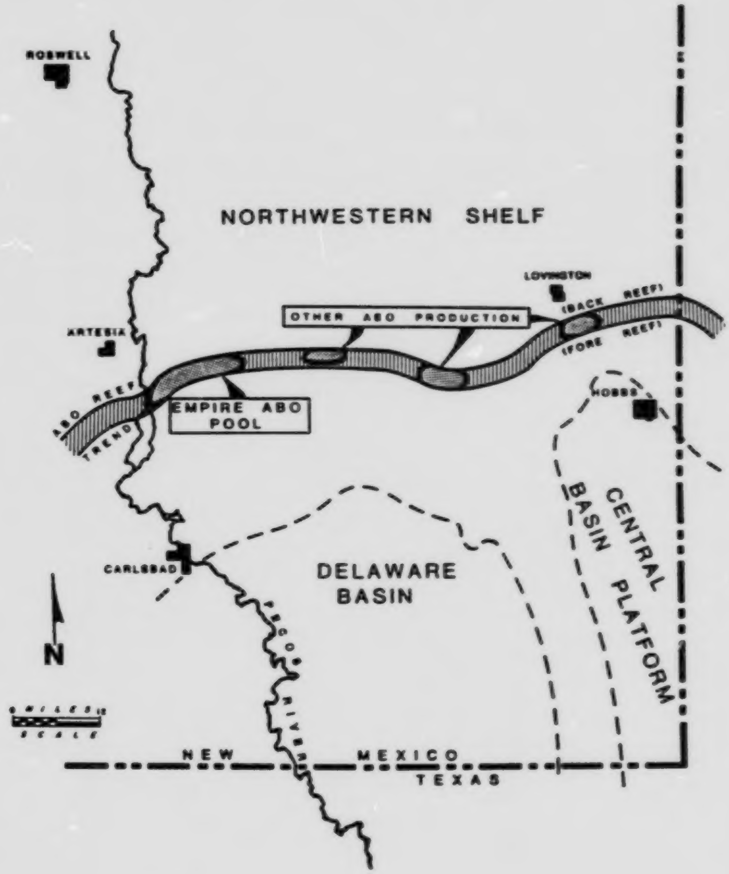

ROSWELL
NORTHWESTERN SHELF
LOVINGTON
OTHER ABO PRODUCTION
(BACK REEF)
(FORE REEF)
ARTESIA
ABO REEF TREND
EMPIRE ABO POOL
HOBBS
CENTRAL BASIN PLATFORM
CARLSBAD
DELAWARE BASIN
PECOS RIVER
N
MILES
SCALE
NEW MEXICO
TEXAS

Fig. 1 - Location of the Empire Abo Pool.

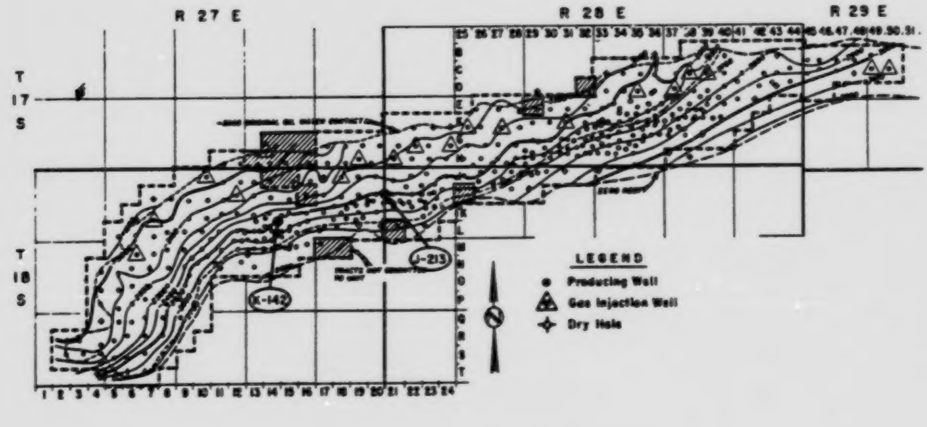

R 27 E
R 28 E
R 29 E
T
17
S
T
18
S
K-142
J-213
LEGEND
Producing Well
Gas Injection Well
Dry Hole

Fig. 2 - Empire Abo Unit Map with drainhole locations.

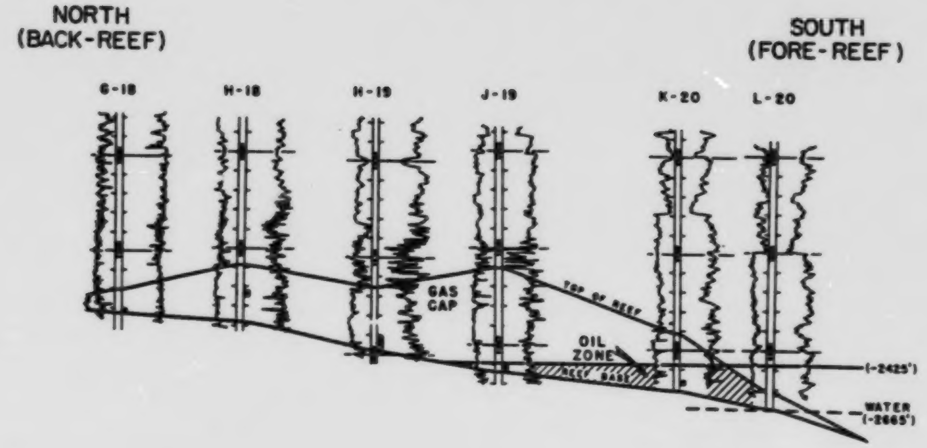

NORTH
(BACK-REEF)
SOUTH
(FORE-REEF)
G-18
H-18
H-19
J-19
K-20
L-20
GAS CAP
TOP OF REEF
OIL ZONE
REEF BASE
(-2425')
WATER
(-2665')

Fig. 3 - Typical Abo Reef cross-section.

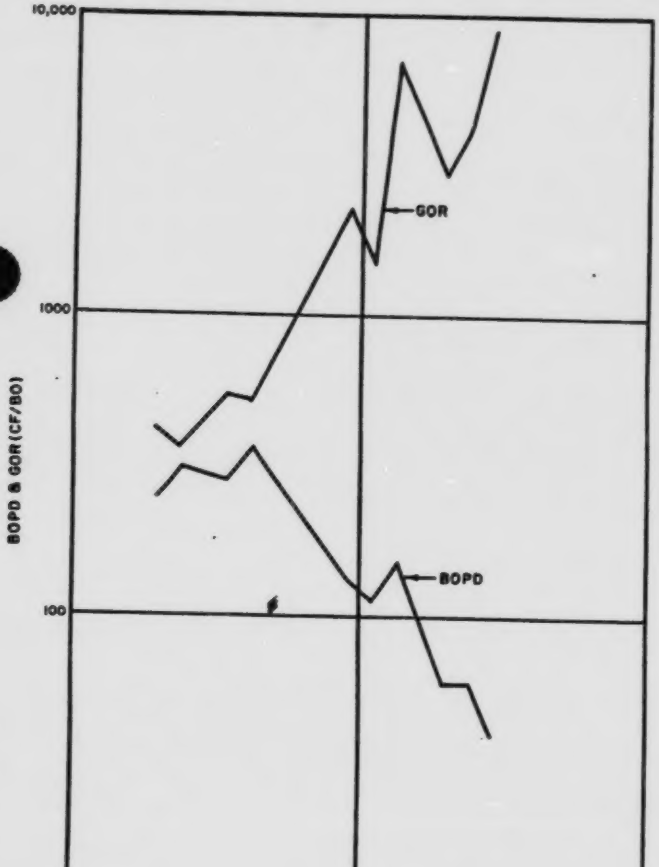


Fig. 4 - Typical Oil rate and GOR performance.

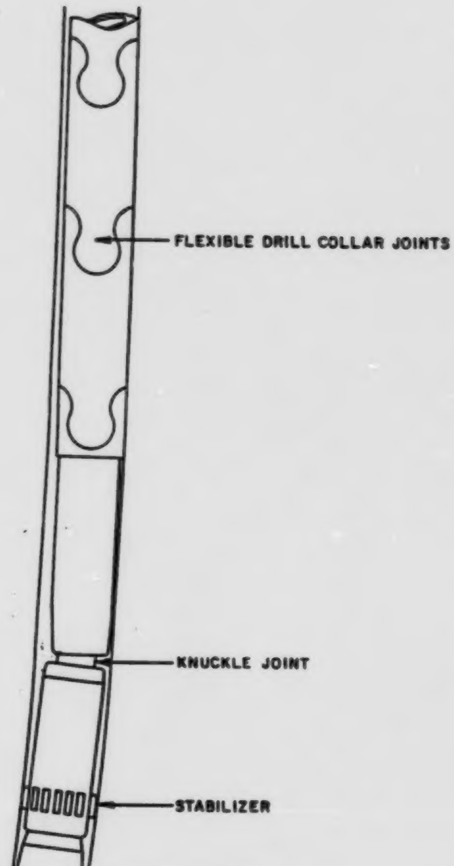
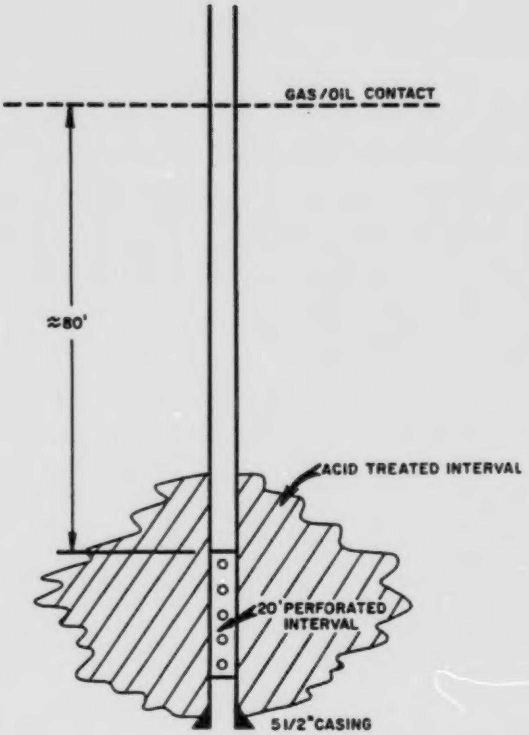

FLEXIBLE DRILL COLLAR JOINTS
KNUCKLE JOINT
STABILIZER
4 3/4" BIT

Fig. 5 - Schematic of angle building bottom hole drilling assembly.


GAS/OIL CONTACT
≈80'
ACID TREATED INTERVAL
20' PERFORATED INTERVAL
5 1/2" CASING

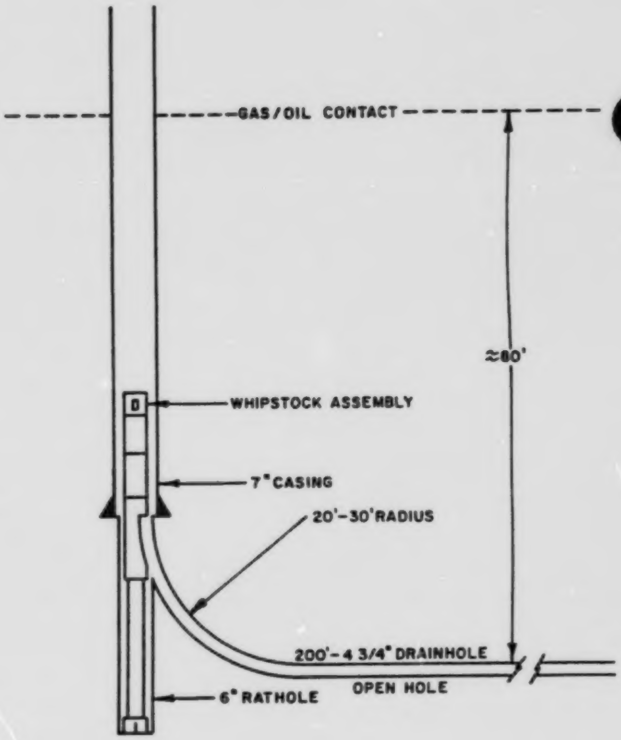

GAS/OIL CONTACT
≈80'
WHIPSTOCK ASSEMBLY
7" CASING
20'-30' RADIUS
200'-4 3/4" DRAINHOLE
OPEN HOLE
6" RATHOLE

Fig. 7 - Ideal Empire Abo drainhole completion.

Fig. 6 - Typical conventional Empire Abo completion.

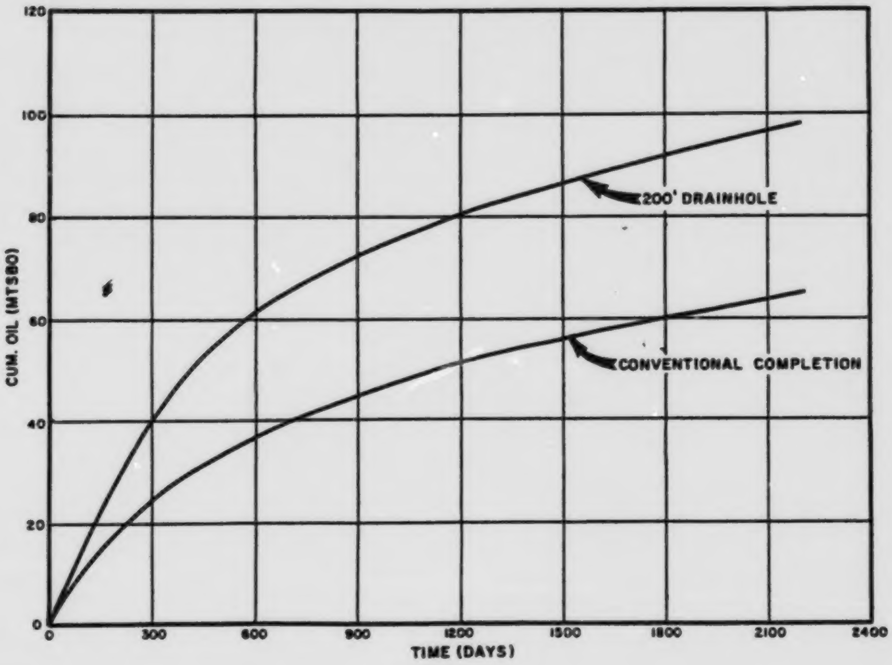


Fig. 8 - Predicted oil recovery versus time for conventional and drainhole completions.

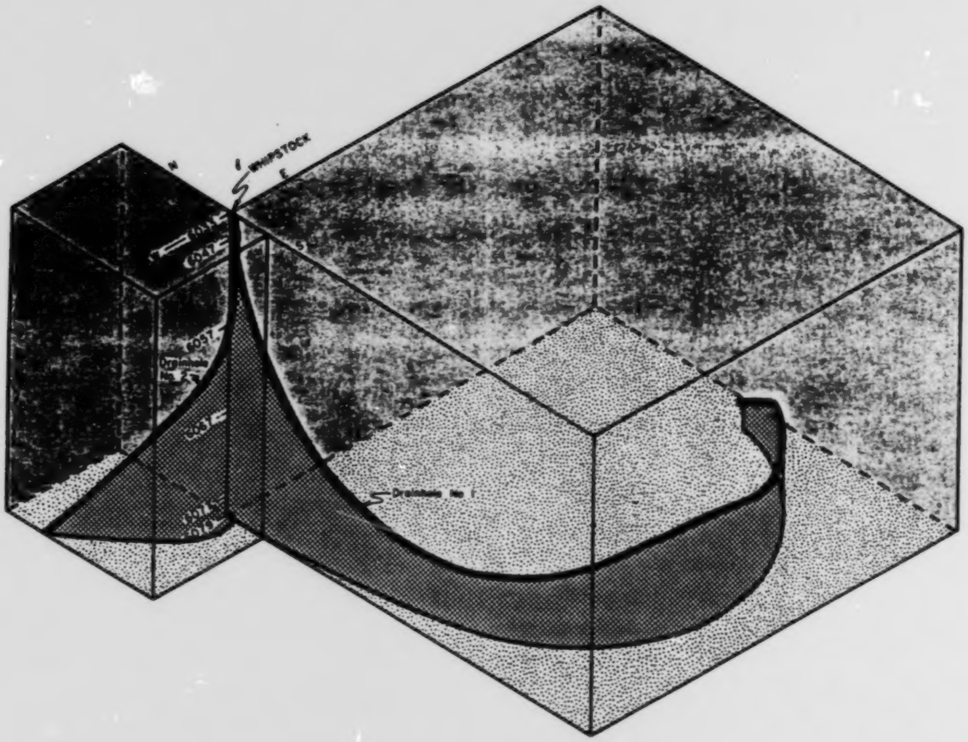

N
WHIPSTOCK
E
S
Drainhole No 1

Fig. 9 - Isometric drawing of K-142 drainholes.

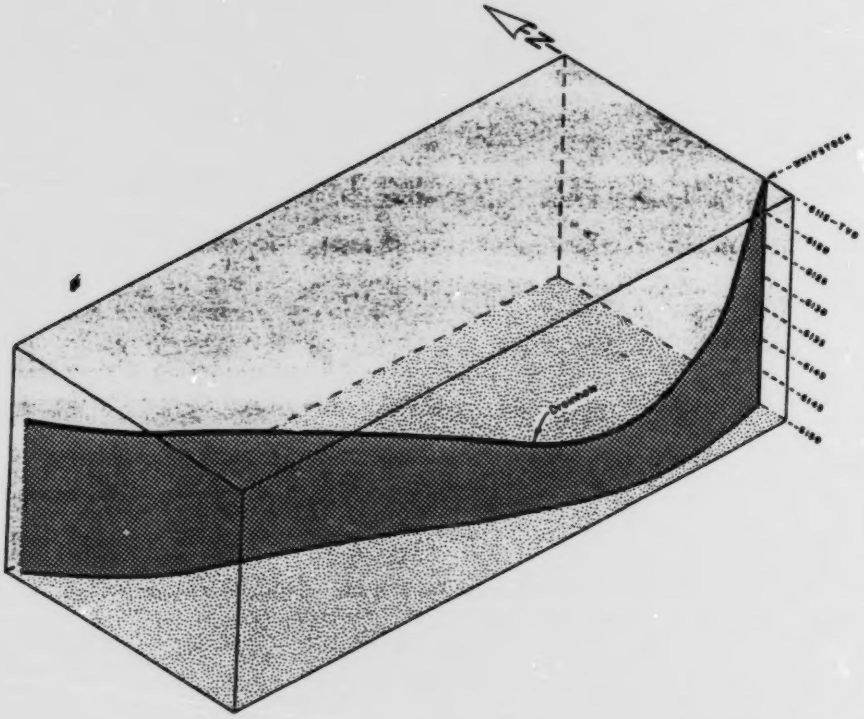

N
WHIPSTOCK
Drainhole

Fig. 10 - Isometric drawing of J - 213 drainhole.

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A REVIEW OF HORIZONTAL WELL TECHNOLOGY

35

by

S. D. Joshi 1/

ABSTRACT

This paper is a review of the state of the art of horizontal well technology for producing heavy oils and tar sands. The review includes a discussion of reservoir engineering, drilling, and completion aspects of horizontal well technology. The available field data are also discussed. The review is restricted to the steam-horizontal well combination technology. The available data demonstrate that for tar sand oil recovery, steam assisted gravity drainage using horizontal wells is an efficient oil production mechanism. For heavy oil recovery, steam assisted gravity drainage as well as steam drive employed with horizontal wells seem to give substantially higher recovery than that obtained using vertical wells. In addition, in mature steam drives with significant steam override, horizontal wells could be used to reduce gravity segregation and produce oil from the bottom layers.

INTRODUCTION

During the last decade, several field studies have reported that horizontal wells may be used to produce conventional oil, heavy oil, and tar sand reservoirs (see Table I). In general, horizontal wells have been successful in enhancing oil production rates and reducing water and gas coning problems. Although horizontal wells have been used to produce 12° API heavy oil using only pump assistance (without steam), some sort of steam and horizontal well combination appears to be necessary to produce highly viscous oils. Table II lists nine horizontal well-thermal projects. The table shows that in conjunction with horizontal wells, steam drive, cyclic steam stimulation, and steam assisted gravity drainage have been used to produce heavy oil and tar sand reservoirs in pilot tests. Presently, only limited results are available.

Currently, technology exists to drill up to 2,000 ft long horizontal wellbores. These long wellbores are used to augment oil production rates; also the high contact area of horizontal wells facilitates the injection of large steam slugs. However, horizontal well drilling costs are about 1.5 to 2 times greater than vertical well costs.

This paper summarizes available laboratory, theoretical, and field results. For completeness, the paper also includes a discussion on horizontal well drilling and completion methods. The paper is a state of the art review of horizontal well-steam technology.

1/ Phillips Petroleum Company,
Bartlesville, Oklahoma, 74004

1986 Tar Sand Symposium
Jackson, Wyoming
July 7-10, 1986

Table I: Horizontal Wells Drilled

Year	Company	Field	No. of Wells	Depth (ft.)	Reservoir Contact Length (ft)	(Horizontal/ Vertical)cost	Comments
1937	--	Yarega, USSR	many	--	1000 max	--	Mine assisted steam
1941	Leo Ranney, et al.	McConnesville, Ohio	6	--	1000	--	Drilled through a tunnel
1942	--	Franklin Heavy Field, Venango County, PA	4 4	388 388	1000 600	Very Expensive --	Drilled through a tunnel
1942(?)	--	Midway Sunset, San Joaquin Valley, CA	2	1100	70	--	Drilled through existing vertical well using downhole motor and flexible drill pipe
1946	--	Round Mountain Field, Kern County, CA	9	1650	56	--	" " " "
1952	--	San Joaquin Valley, CA (Midway Sunset)	1	1200 3700	50 50	--	Six drain holes from a well Six drain holes from a well
1952	Venezuelan Oil Concessions, Ltd.	La Pas Field, Western Venezuela	?	10,000	50-100(?)	--	Drilled to reduce gas coning
1952	Long Beach Oil Development Co.	Los Angeles Basin Area (Wilmington Field)	8	3500 to 4800	50	--	In each well 6 to 8 drainholes were drilled. In some wells several drainholes were drilled at depth to reach many zones
1957	--	USSR	1	1000	300	--	Production Well
1967	--	China	1	3600	1600	--	Produced 5 to 10 times more fluid than a vertical well but collapsed in 7 days.

TABLE I (cont'd)

Horizontal Wells Drilled

Year	Company	Field	No. of Wells	Depth (ft.)	Reservoir Contact Length (ft)	(Horizontal/ Vertical)cost	Comments
1968		Marcovo, East Siberia, USSR	1	7200	1800	--	--
1977	Conoco	Tisdale, Wyoming	6	--	1700 max	--	Drilled from tunnel
1978	Esso, Canada	Cold Lake, Alberta	1	1558	1000	8-12	Drilled from the surface into unconsolidated sand, steam stimulation
1979	Texaco	Fort McMurry, Alberta, Canada	3	415	1000	5-6	Steam stimulation. Presently shut down
1979	Esso, Canada	Normal wells under Makenzie River, Alberta, Canada	1	1603	1860	--	--
1980-81	Elf-Aquitaine & IFP	Lacq Field Southwest France	1	2195	330	4.3	Drilled from the surface
"	"	" "	1	4100	1214	3.5	Drilled from the surface
1981-83	Elf-Aquitaine & IFP	Rospo Mare, Offshore Italy	1	4500	1988	2.1	Drilled into fractured limestone. Produced 15 times better than a vertical well. Reduced water coning.
"	"	Castera Lou, South France	1	9500	1300	2.1	Not only increased production but reduced water coning in a limestone formation.
1980-84	ARCO	Empire Abo Unit, New Mexico	2	6200	300-400	2	Drilled new wells from the surface.

TABLE I (cont'd)

Horizontal Wells Drilled

Year	Company	Field	No. of Wells	Depth (ft.)	Reservoir Contact Length (ft)	(Horizontal/ Vertical)cost	Comments
1981-84	ARCO	Empire Abo Unit, New Mexico	8	6200	300-400	$250,000/well	Drilled through existing vertical well
1982-84	ARCO	Southeast Douglas Garfield County, OK	1	6500	300-400	" "	Drilled from the existing low producer vertical well into fractured Mississippi limestone.
1985	Esso, Canada	Cold Lake, Alberta Canada	1	1558	3330	--	Cyclic steam stimulation
1985	Petrobras	Fazenda Bèlam Field	1	1000	554	--	Produces five times better than the surrounding vertical wells.
1985	Sohio	McMullen Co., Texas	1	10300	1908	--	Long horizontal well
1985	Sohio	Glasscock Co., Texas	1	--	295	--	Short drainhole
1985	Sohio	Prudhoe Bay, Alaska	1	8989	1400	2	Three fold increase in oil production rates over conventional well.
1986	Sohio	Prudhoe Bay, Alaska	1	9000	--	1.4	Three fold increase in oil production rates over conventional well

TABLE II: HORIZONTAL WELL - STEAM FIELD PROJECTS

			Horizontal Wells					
Company & Year	Location	Reference	Number	Length (ft)	Steam Process	Cum. Oil Production (bbls)	SOR	Status & Comments
Yerga	USSR	Butler, 1984	Many	300 max	--	--	--	Active/Mine Assist.
Signal Oil Co. (1965-66)	Sunny Side, Carbon County Utah	Marchant, 1984 Combs, 1967	3	370 ft. but 50 ft. open to pay zone	cyclic & drive	566	23	Inactive, 9°-10° API oil, drilled from a outcrop side
Petro-Canada & other companies MAISP-I (1978)	Fort McMurry, Alberta, Canada	Towson, 1984	1 2	330 met 120	cyclic & drive	--	16	Inactive, ~10°API, drilled from a outcrop side
Hopco (1979)	Kern County, California	Rintoul, 1982 O & G J., 1982	4 4	430 730	cyclic	19,907	--	Inactive, 13° API oil, drilled from a shaft
Esso - I (1979) Esso - II (1985)	Cold Lake, Alberta, Canada	Bezair & Markiw, 1979 Baldwin et al., 1983 MacDonald, 1985	1 1	1000 3200	cyclic steam & steam assisted gravity drainage	--	--	Active, ~10°API Active, ~10°API
Texaco (1979)	Fort McMurray Alberta, Canada	Loxam, 1982 Pugh, 1982 Oil Week, 1986	3	1000	cyclic & drive	--	--	Inactive, ~10°API drilled from the surface
(1986)	California	--	1	--	cyclic	--	--	Active, 13°API oil
Petrobrass (1985)	Fazenda Belam Field, Brazil	EOR Week, 1985	1	544	(?)	75 BOPD	--	14°API oil
Planned Project								
MAISP (1985-87)	Athabasca Tar Sands, Alberta, Canada	Best et al., 1985	356	--	--	--	--	Mine/shaft project, 10°API oil

STEAM PROCESSES

Horizontal wells can be used for cyclic steam stimulation, continuous steam drive, and the steam-assisted gravity drainage process. In many heavy oil and tar sand reservoirs, cyclic steam stimulation is necessary to establish initial steam injectivity. A review of various production techniques is given below.

Cyclic steam stimulation

Coats (1984) described a physical simulator to study steam stimulation using horizontal wells. Toma et al.'s (1984) laboratory experiments indicate that bitumen recovery depends upon the axial pressure drop in a well. The recovery could be further enhanced by using solvents and carbondioxide.

Gussis's (1984) numerical study compared the performance of a steam stimulation of a vertical well and a horizontal well. The reservoir properties were as follows: gravity 12° API, h = 100'. In the four layers of a five layer model, the vertical permeability was assumed to be half of the horizontal permeability. In one layer, the vertical permeability was 1/10th of a horizontal permeability. The horizontal well was assumed to be 840 ft long. As shown in Fig. 1, at the end of one cycle (90 days; 7 days production, 17 days injection, 4 days soak, and 62 days production), cumulative production from a horizontal well was about five times larger than that obtained from the vertical well. However, the large difference between horizontal and vertical well production will decrease in successive stimulation cycles.

Gussis (1985) numerically compared 12° API oil production from three different horizontal well patterns. Each pattern, as shown in Fig. 2, drained 80 acres from a 100 ft thick reservoir using 8 horizontal wells. The pattern descriptions and their recovery with cyclic steam stimulation is as follows: I) four pairs of 2,000 ft long horizontal wells, spaced 218 ft apart, at the reservoir bottom. The wells were drilled to obtain a line drive with 2,000 ft between the two consecutive wells. This configuration produced 27% of OOIP (original oil in place) in 9.3 years. II) four 2,000 ft wells drilled at the reservoir top and four at the reservoir bottom, with 2,000 ft between the consecutive line drive wells. The pattern produced 26.5% of OOIP in 9.0 years. III) eight wells drilled radially outward from the center of an 80 acre square drainage area. Wells located on the square diagonal were longer than those located along the square center lines. This pattern produced 20.8% of OOIP in 9.0 years.

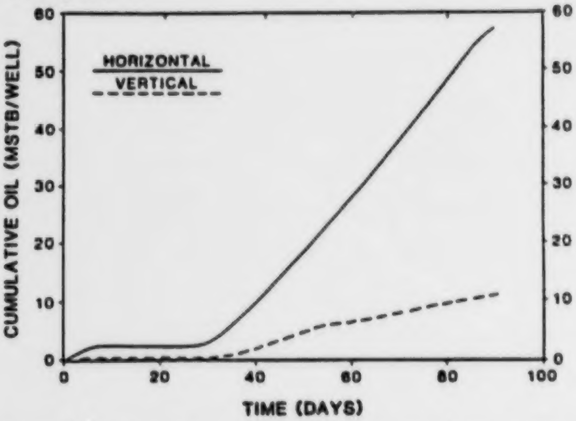

Figure 1. A comparison of cyclic steam stimulation using horizontal and vertical wells (Gussis, 1985).

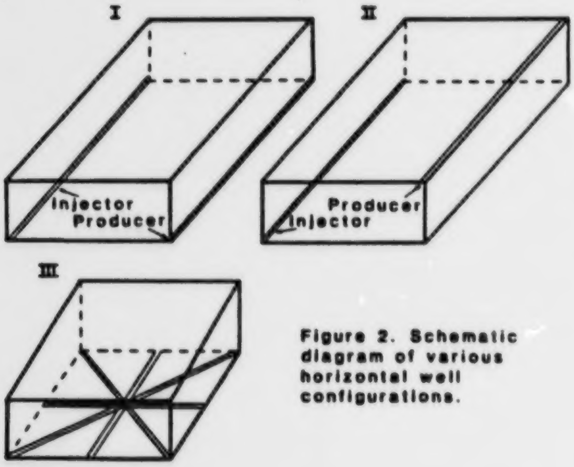

Figure 2. Schematic diagram of various horizontal well configurations.

The best option from the recovery standpoint is pattern I, i.e., a line drive using parallel horizontal wells located at the reservoir bottom. In pattern II, the injection well located near the reservoir top results in a large heat loss to the overburden. In pattern III, a large distance between well tips at the outer boundary of radially drilled holes results in a poor sweep near the reservoir outer boundaries, and thus poor recovery.

Steam drive

A laboratory study and a few numerical studies report results with steam drive using horizontal wells. Huygen and Black's (1982) laboratory study shows that continuous steam circulation through a single perforated horizontal well would be an efficient process to recover viscous bitumen. In their well scheme, two vertical wells intersect horizontal well tips. One vertical well serves as a continuous steam injector and the other acts as a producer. The vertical fractures drastically reduce oil recovery using Huygen and Black's (1982) well scheme.

Results of numerical simulation are reported in the following papers: Rial (1984) considered 15° API oil, Huang and Hights (1985) considered 13° API oil, Gussis (1983) considered 12° API oil, and Khosla and Cordell (1985) and Jain and Khosla (1985) considered viscous Alberta bitumen, $\simeq 10^\circ$ API oil. The following paragraphs include a brief description of numerical simulation results.

Rial (1984) simulated a steam drive between two vertical wells for the Kern River, California type reservoir, assuming $A = 2.5$ acres and $h = 80'$. The vertical injection and production wells were located at the centers of the two opposite edge walls of a cubical drainage volume. Rial also simulated steam drive between a 330 ft long horizontal injector and a vertical producer. In a cubical drainage volume, the horizontal injection well was located at the reservoir bottom along the one edge, while the vertical producer was located at the center of the opposite wall. In five years, a horizontal-vertical well scheme produced 64% of OOIP as compared to 51% of OOIP for the vertical well scheme. Additionally, in 15 years, the horizontal model produced 71% of OOIP in contrast to 58% of OOIP by the vertical well model.

To develop a 125 ft thick, 13° API oil field, Huang and Hight (1985) numerically studied several horizontal-vertical well combinations. They used 18.5 acres and found that the best pattern layout recovers 72.2% OOIP in seven years. The best pattern includes four horizontal production wells near the reservoir bottom, drilled radially from the four corners of a square drainage area towards the center. The pattern also includes five vertical injection wells, one at the pattern center and the remaining four located at the center of each square drainage boundary.

In seven years, Huang and Hight's (1985) simulation shows 72.2% recovery of 13° API while Rial's (1984) results show 67.8% recovery of 15° API oil. Although these recoveries are comparable, a lower recovery in Rial's prediction may be due to gravity segregation introduced in his model. In Rial's four layer model, permeability of the top two layers was 5,000 md, while permeability of the bottom two layers was 2,000 and 1,400 md. In contrast, Huang and Hight used a uniform horizontal permeability of 3,000 md and a uniform vertical permeability of 900 md. The oil recovery comparison above demonstrates that in spite of gravity segregation, a steam drive between horizontal-vertical well combinations shows a high oil recovery.

Huang and Hight (1986) numerically investigated the use of horizontal wells in a mature vertical well steam drive with a significant steam override. Their simulation assumed a 125 ft thick, 13° API oil reservoir with 3,000 and 900 md horizontal and vertical permeabilities, respectively. A base case vertical well production scheme included a nine spot - 18.5

acre spacing - vertical well pattern. As shown in Fig. 3, vertical wells showed an overall 64.7% OOIP recovery in 15 years. However, saturation profiles showed a significant steam override with 60% oil saturation left in the bottom zones. Almost the same overall recovery could be obtained in a shorter time, (11 years), by employing an inverted 13 spot instead of 9 spot pattern. This pattern conversion still leaves high residual oil saturations in the bottom zones and still shows significant steam override. To mitigate the steam override, after six years of 13 spot operation, eight, 374 ft long horizontal wells were introduced along the edge of a square drainage boundary. The introduction of eight horizontal producers along with vertical producers not only shortened the project life to nine years, but it also increased the overall recovery by one percent to 65.9% of OOIP. Since the horizontal wells have a large fluid carrying capacity, a simulation run was made where along with the central injector, the four infill wells were also converted into steam injectors. The 13 spot horizontal-vertical well pattern (5 vertical injectors, 8 vertical producers, 8 horizontal producers) produced 74.7% OOIP in 11 years, a significantly higher recovery than the other previously noted well schemes. A good sweep efficiency of horizontal wells, especially in the bottom layers, results in a high recovery. These results indicate that horizontal wells can be used in a mature steam drive to reduce gravity segregation, improve sweep efficiency, and produce more oil.

Gussis (1985) also simulated steam drive using various horizontal well configurations for producing 12^{o} API oil. Figure 2 depicts some of these configurations. Gussis notes that initial cyclic steam followed by a steam drive between two 2,000 ft long wells, placed 416 ft apart (20 acres), produces 42% of OOIP in nine years. This recovery is substantially lower than Rial's (1984) 69% recovery in 9 years and Huang and Hight's (1985) 72.2% recovery in seven years. Gussis's low recovery is mainly due to his high viscosity oil (12^{o} API) as compared to that used by Rial (15^{o} API) and Huang and Hight (13^{o} API). In addition, Gussis's higher well spacing and different well configuration may also have caused lower recovery. These results show that a steam drive between two long horizontal wells is not efficient to produce highly viscous oil. A steam drive using a horizontal-vertical well combination may give better oil recovery than parallel horizontal wells.

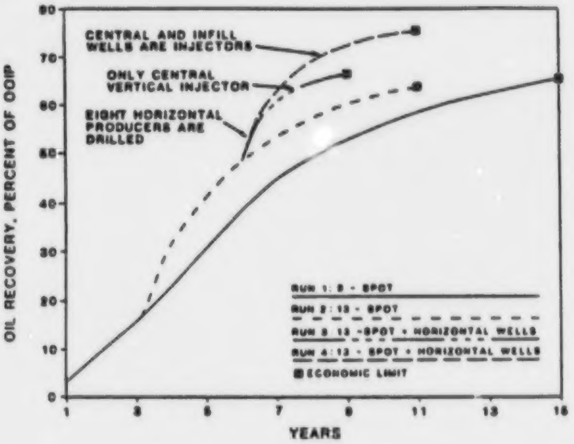

Figure 3. A comparison of various production schemes with and without horizontal wells in a mature steam drive (Huang and Hight, 1986).

Inefficiency of steam drive to produce highly viscous oil, especially between parallel horizontal wells, is further confirmed by the numerical results of Khosla and Cordell (1985) and Jain and Khosla (1985). Both of these investigators obtained very low recovery by using steam drive for producing tar sands.

Khosla and Cordell (1985) have reported numerical results for bitumen production from the McMurray formation in Athabasca Tar Sand deposits in Alberta, Canada. The authors modelled a 49 ft thick reservoir with a drainage area of 5.93 acres per well. In all calculations horizontal well length was assumed to be 1640 ft. The results were obtained with two types of reservoirs: 1) bottom water providing good injectivity and 2) no bottom water hence, minimum steam injectivity. Table 3 compares oil production obtained under different scenarios. In all scenarios, initially all wells were steam stimulated. They used a parallel horizontal well configuration, located near the reservoir bottom with a spacing of 148 ft between the wells. This configuration shows about 85% of OOIP production in three years, assuming the same horizontal permeability in the oil and bottom water zones. However, if the bottom water zone permeability is twice that of the oil zone permeability, the percentage of OOIP recovered is only 15.8%. This indicates that most of the injected steam enters the bottom water zone. If the distance between the wells is doubled to 295 ft and a high permeability streak is introduced between the injector and producer, most of the injected steam travels through the high permeability streak, giving early steam breakthrough and recovering only 25.4% of OOIP. These results indicate that steam drive using horizontal wells in bitumen reservoirs will be successful if the bottom water zone has permeability the same or less than the oil zone, there are no high permeability streak zones, and spacing between the wells is close. Thus, application of steam drive to bitumen reservoirs appears limited. In contrast, Khosla and Cordell (1985) found that with or without the bottom water zone, the steam assisted gravity drainage process, described in the next section, gives significantly higher recovery than either cyclic steam stimulation or steam drive. For example, a 1640 ft long horizontal well with two vertical injectors could produce 77% of OOIP in four years by using a steam assisted gravity drainage process.

Jain and Khosla (1985) investigated the possibility of continuous steam circulation through a horizontal well and an intersecting vertical well. The process is similar to Conoco's 'FAST' process where steam is rapidly circulated through a horizontal fracture (Britton et al., 1983). To produce bitumen, as compared to steam assisted gravity drainage a continuous steam circulation process was found to be thermally inefficient. The comparison of the following three well configurations and their results shows the effectiveness of steam assisted gravity drainage: I) A continuous steam circulation through a 985 ft long horizontal well and intersecting vertical well produces 79 bbl/day for about 6 years. II) A steam drive between two 490 ft long horizontal wells, spaced 197 ft apart, produces 138 bbl/day for 7 years, and III) A steam assisted gravity drainage using a 1310 ft long horizontal producing well with two vertical steam injectors, spaced equally from the both well ends, produces 315 bbl/day for 7.5 years.

The above results show that from a recovery standpoint, steam assisted gravity drainage using horizontal wells is the best process to produce tar sand reservoirs. The process and the reasons for its superior performance are given below.

Steam assisted gravity drainage

In cyclic steam stimulation and in steam drive, even though gravity drainage plays a part in oil production, most of the oil production is due to the reservoir pressure gradient. In cyclic steam it is the pressure gradient between the reservoir and production well, and in steam drive, it is the pressure gradient between the injection and production wells which determines oil production rates. On the other hand, in the steam assisted gravity drainage process there is no pressure drop, other than gravity head, between the injection and production wells. The oil is produced solely by gravity drainage. The rate of gravity drainage is enhanced by steam heating which reduces oil viscosity. Even then, oil production rates are only of the order of 0.3 bbl/day/ft length of a well. Sufficiently high production rates are obtained by using 1000 to 3000 ft long wellbores.

Table III. A Comparison of Bitumen Production With Different Oil Production Schemes Using Horizontal Wells (Khosla and Cordell, 1985).

Well Scheme	Drainage Area (acres)	Operating Life (years)	Cumulative Oil steam ratio	Average Oil Rate (bbl/day)	% OOIP Recovery
Steam drive between two, 1640 ft long, horizontal wells					
i) Wells 148 ft apart, uniform permeability	5.6	3	0.23	353	85.0
ii) Wells 148 ft apart, a high permeability streak	5.8	3	0.10	69	15.8
iii) Wells 295 ft apart, a high permeability streak	11.7	3	0.14	221	25.4
Gravity Drainage With Two Vertical Injectors and a 1640 ft long horizontal producer					
i) High bottom water	5.9	4	0.16	245	73.8
ii) High bitumen in the bottom zone	5.9	4	0.20	300	77.0

The absence of an externally imposed pressure gradient in a reservoir, reduces steam channeling, improves sweep efficiency, and gives high recovery. The high recovery is further improved because of better displacement efficiency (low residual oil saturations) of the gravity drainage process as compared to any other production process.

Butler and associates (1981a, 1981b, 1984, 1985a, 1985b) introduced the concept of steam-assisted gravity drainage using horizontal wells. The process is very much similar to what happens in a bathtub, where steam rises and water drains below. Figure 4 taken from Joshi and Threlkeld (1985) and Joshi (1986) shows a counter current flow of hot oil and steam with two parallel horizontal wells. The well pair is located near the bottom of an oil column with the injection well on top and the production well at the bottom. The wells are located as close as possible with no pressure drop, other than gravity head, between them. A minimum pressure drop between the two wells prevents short circuiting of the injected steam.

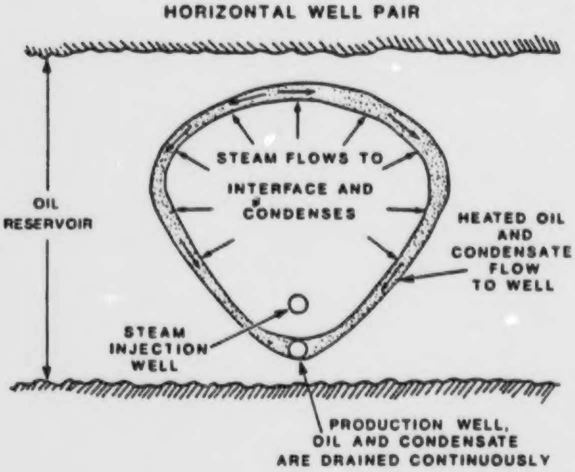

Figure 4. Steam assisted gravity drainage concept.

Along with the high sweep and displacement efficiencies other advantages of steam assisted gravity drainage are as follows: 1) in contrast to cyclic steam and steam drive, hot oil is produced as soon as it is displaced from the formation, 2) almost independent paths are formed for oil, condensed water, and steam flow, resulting in favorable relative permeability effects for oil flow, 3) in the case of early steam breakthrough, injection can be stopped for a time period and then reinitiated without a significant loss in process efficiency. The disadvantages of the process are: 1) a relatively thick (≃50 ft) oil column is needed, 2) several oil zones, separated by thick, continuous shale barriers may require drilling of horizontal holes in each layer to be drained.

Figure 5 shows three possible well configuration schemes for field application. Butler and associates (1981a--b, 1984) developed a semi-analytical solution to calculate oil production rates and oil steam ratios using parallel horizontal wells. They have also established dimensionless parameters to scale-up laboratory data to field values. Their laboratory experiments with a Cold Lake, Alberta bitumen show good agreement with theoretical results. Griffin and Tronfimenkoff (1984) developed an analytical model to calculate oil production rates using a vertical injector and horizontal producer. Their laboratory results with bitumen show good agreement with the theoretical solution. Joshi and Threlkeld's (1985) and Joshi's (1986) laboratory results show that vertical fractures help steam to rise vertically upward, resulting in a high initial oil recovery and high initial oil-steam ratios. Joshi's (1986) laboratory results with 17° API oil show that non-continuous shale barriers have a minimum effect on steam assisted gravity drainage. His results also show that vertical injectors and a horizontal producer is a preferred well scheme for reservoirs with non-continuous shale barriers. All the laboratory results indicate that the sweep efficiency will be high for all well schemes even in the presence of non-continous shale barriers. The above noted high sweep efficiency is also confirmed by numerical simulation (Jain and Khosla, 1985; Khosla and Cordell, 1985). Jain and Khosla's numerical simulation shows that the steam assisted gravity drainage process gives a higher recovery of OOIP than cyclic steam or steam drive. As shown in Table 3, Khosla and Cordell's (1985) simulation also shows a superior performance of steam assisted gravity drainage in producing bitumen.

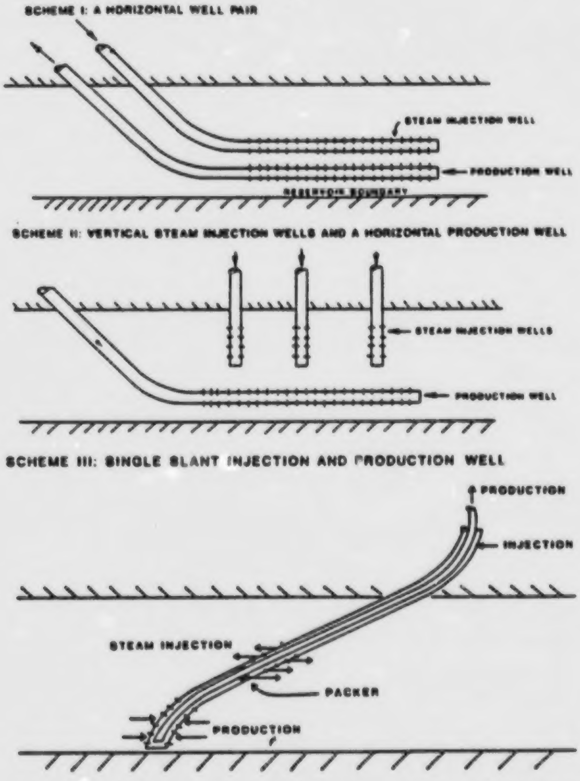
SCHEME I: A HORIZONTAL WELL PAIR
STEAM INJECTION WELL
PRODUCTION WELL
RESERVOIR BOUNDARY
SCHEME II: VERTICAL STEAM INJECTION WELLS AND A HORIZONTAL PRODUCTION WELL
STEAM INJECTION WELLS
PRODUCTION WELL
SCHEME III: SINGLE SLANT INJECTION AND PRODUCTION WELL
PRODUCTION
INJECTION
STEAM INJECTION
PACKER
PRODUCTION

Figure 5. Different well configuration schemes for steam assisted gravity drainage.

Figure 6 compares numerical and analytical solution predictions for steam assisted gravity drainage. As shown in the figure, Jain and Khosla's (1985) numerically calculated steam oil ratios show values about twice those calculated using Butler and associates' (1981a-b, 1985a-b) analytical solution. In addition, numerically and analytically calculated oil production rates show the same trend and approximately the same values, except that the numerical calculation lags behind the analytical solution by about 500 days. Jain and Khosla (1985) explain the discrepancy by the following three factors: 1) The analytical solution assumes the existence of a hot plane over the horizontal well starting from the first day. 2) The analytical model ignores while the numerical model includes reservoir heterogeneities. 3) Grid block sizes in the numerical model affect the production rates, but cumulative production over the well life is not affected.

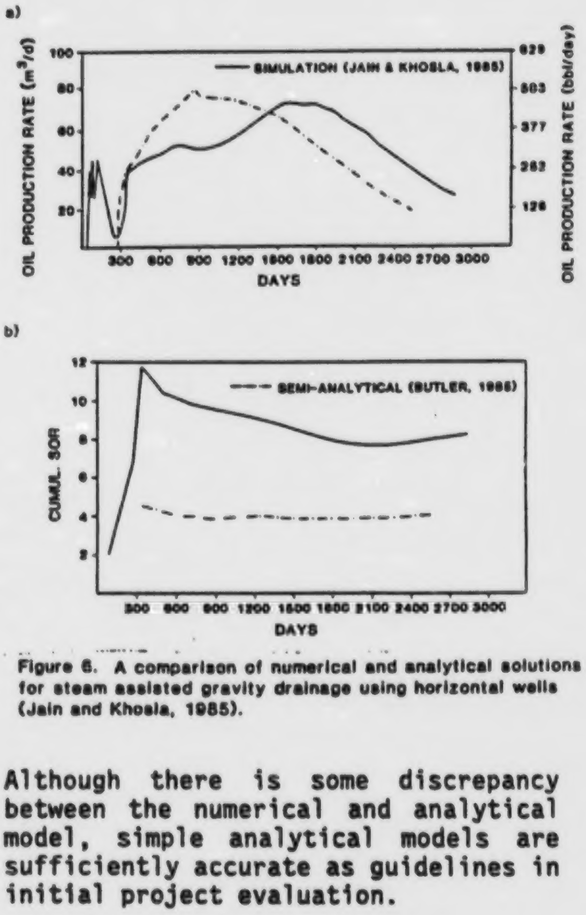

Figure 6. A comparison of numerical and analytical solutions for steam assisted gravity drainage using horizontal wells (Jain and Khosla, 1985).

Although there is some discrepancy between the numerical and analytical model, simple analytical models are sufficiently accurate as guidelines in initial project evaluation.

Other methods

Dismukes (1985) suggests a continuous steam soak method using horizontal wells. Instead of injecting steam into the formation, the method suggests circulating it through the wellbore, which has several U-shaped tubes. The steam enters the wellbore through one leg of a U-tube and condensate returns to the surface through the other leg of a U-tube heat exchanger. Reservoir heating is mainly by conduction heat transfer. The authors estimate about 15 to 20% OOIP recovery in 15 to 20 years.

Some patents describe the use of electrical, microwave, and radio frequency heating of oil sands using horizontal wellbores (Perkin, 1984).

HORIZONTAL WELL DRILLING

As seen from Table I, several companies have drilled horizontal holes in the last decade. Initially, horizontal drilling was developed for shallow reservoirs using a shaft and tunnels as described by Best et al. (1985), Smith and Butler (1979), and Quinn and Duncan (1976). However, recent advances in drilling technology facilitate drilling horizontal wells from the surface. Technical advances have successfully solved problems such as bit weight, directional control, and the dragging and sticking of drill pipe. Significant advances have also been made in logging and completing these wells. Presently, available technology can be classified as follows: 1) short, 100-200 ft long drainhole drilling (SDHD), 2) medium length, 100-700 ft long drainhole drilling (MDHD) and 3) 1000-2500 ft long horizontal well drilling (LHWD).

Short drainhole drilling (SDHD)

Dickinson and Dickinson (1985), Pendleton and Ramesh (1985), Rintoul (1985), and Dickinson et al. (1986) describe drilling 100-200 ft long drainholes in an unconsolidated formation using water jets. As shown in Fig. 7, the short radial drainholes are drilled through an underreamed portion of an existing vertical well. The process involves the following operations: 1) mill a 5 to 10 ft window in the casing and underream a 4 ft diameter cavity using water jets. 2) lower a whipstock in the hole and erect it at a right angle to the hole. 3) use a specially developed pipe with water jets to drill a 4 inch diameter hole. 4) cut off the production tube down hole. 5) de-erect the whipstock, turn it, and re-erect it at a desired angle with the last drilled hole. 6) drill a second hole using steps 1 through 5. The production tubing could be perforated and then gravel packed for sand control (Pendleton and Ramesh, 1985). Normally a slotted liner is run into the underreamed hole. The authors also briefly describe a specialized logging tool for these holes.

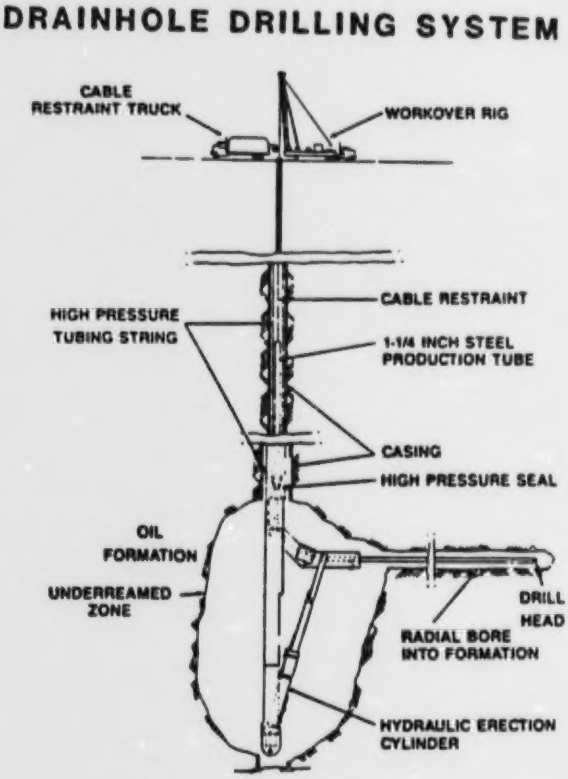
DRAINHOLE DRILLING SYSTEM
CABLE RESTRAINT TRUCK
WORKOVER RIG
CABLE RESTRAINT
HIGH PRESSURE TUBING STRING
1-1/4 INCH STEEL PRODUCTION TUBE
CASING
HIGH PRESSURE SEAL
OIL FORMATION
UNDERREAMED ZONE
DRILL HEAD
RADIAL BORE INTO FORMATION
HYDRAULIC ERECTION CYLINDER

Figure 7. A schematic of short drainhole drilling (Dickinson et al., 1986)

Medium length drainhole drilling (MDHD)

In the early 1950's Stromont (1953) and Eastman (1954) described lateral drainhole drilling tools. Recently, Stramp (1980), Holbert (1981), and Gorody (1984) have discussed drilling 200-700 ft long drainholes through an existing vertical well. As described in the above references, first a window is cut into the existing casing by a milling operation. Then "wiggly" collars, shown in Fig. 8, along with the angle buildup assembly are used to drill off the whipstock and into the formation, turning 3° per ft with a turning radius of 30 ft. This continues up to 85°, and then, a second stabilized bottom hole assemble drills the rest of the drainhole. Texas Eastern Company markets a similar drilling technology (Gorody, 1984).

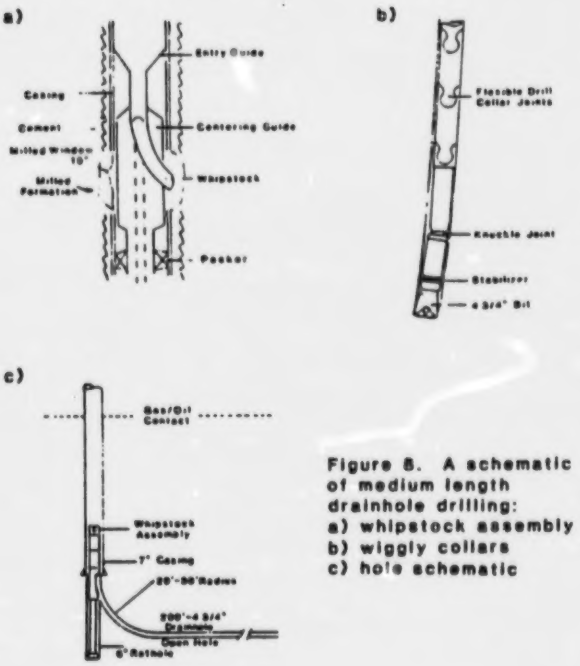

Figure 8. A schematic of medium length drainhole drilling:
a) whipstock assembly
b) wiggly collars
c) hole schematic

Holbert's (1981) theoretical calculations show that hydraulics and friction combine to limit the maximum drainhole length to between 600 to 1,200 ft. So far, Texas Eastern reported the maximum drilled drainhole length of 700 ft (Gorody, 1984). Recently, technology has been developed to complete such a hole by inserting a slotted liner. A sufficiently small gauge wire mesh screen could be wrapped on the liner to prevent silt and sand from entering the well, especially in an unconsolidated formation. The major disadvantage of this scheme is that it is difficult to push most of the conventional vertical well tools through a sharp, 20-30 ft curvature radius turn. This may also present some well treatment problems.

Long horizontal well drilling (LHWD)

Institute France du Petrole (IFP) and Elf Aquitaine have developed the technology to drill, complete, and log 2000 ft long horizontal wells. So far they have drilled four horizontal wells in Europe (Giger, 1982; Giger and Jourdan, 1984; and Reiss, 1985). Most of these wells were drilled at 2000 to 10,000 ft depths in a consolidated formation. The Rospo Mare well, offshore Italy, produces 12° API heavy oil from a fractured limestone formation. A combination of regular drill bits with bent subs and downhole mud motor was used to drill a 2000 ft long well at about 6000 ft depth. A slotted liner was inserted in the hole and a special logging technique was also developed (Baron and Wittrisch, 1982). Dorel (1983) describes their success in selective completion by cementing and thereby blocking off a high water producing zone in a 1086 ft long horizontal well, Lacq 91, in France.

Most of the heavy oil and tar sands reservoirs are not only unconsolidated sands, but are also shallow, i.e., depth on the order of 400 to 2000 ft. Such a shallow depth poses a problem for kicking off from a vertical to a horizontal direction. The turning radius can be very long, especially at shallow depths. To overcome the depth problem, Texaco used a 45° slant rig to drill three, 1000 ft long horizontal wells at 415 ft depth in the Athabasca Tar Sand deposits in Alberta, Canada. Pugh (1982) and Loxam (1982) report a drilling method using a specially developed, hydraulically powered slant rig. A downhole mud motor powers the drill bit and a hydraulic force applied to the drill pipe at the surface provides the needed weight on the bit. A similar hydraulically powered, slant rig technique is used by several river crossing rigs (Thomas, 1982; and Hair and Shiers, 1985). These river crossing rigs may be used to drill long horizontal wells.

Bezair and Markiw (1979), Baldwin et al. (1983), and MacDonald (1985) describe Esso Canada's experience in drilling horizontal holes. Bezair and Markiw (1979) describe drilling a 1059 ft long horizontal hole at about 1500 ft depth in Cold Lake, Alberta, Canada. MacDonald (1985) describes Esso's plan to drill a 3228 ft long horizontal hole in Cold Lake at 1530 ft depth. A schematic of their well and planned drilling program is shown in Fig. 9. Bezair and Markiw (1979) describe the drilling program used to drill Esso's first horizontal hole as follows: first drill up to 150 ft depth using regular rotary drilling; then set the surface casing and kick off using a downhole mud motor and a bent sub. The drilling angle build up was 4-1/4° per/100 ft until reaching 90°. The surveying equipment was installed on a non-magnetic drill collar, located away from the bit. During drilling, the vertical depth of a horizontal well was controlled within 0.1%, but in a lateral direction control was only within 2% i.e., ±30 ft at 1500 ft depth. To overcome this problem, after drilling the well Esso plans to use a vertical seismic technique to pin-point the lateral well location (MacDonald, 1985).

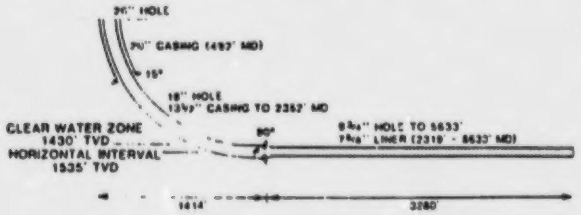

Figure 9 A schematic of a long horizontal well (MacDonald, 1985)

Drilling summary

Various drilling technologies are available to drill horizontal holes. Other than short length drainholes (SDHD), most of these wells could be completed only using slotted liners. Recently, Huang and Brown (1984) have suggested methods to gravel pack horizontal wells. However, field data are not available to evaluate the effectiveness of such packs in sand control. Presently very little information is available for cementing the highly deviated wellbores (Jordan, 1985). Further improvements are needed in the area of cementing and selective completions of horizontal wells. Improvements are also required in trajectory control of a horizontal well in the lateral direction. Recent developments in MWD (measurement while drilling) offers the possibility for more exact trajectory control (Johancsik, 1985). Some of the new technologies to drill long horizontal wells by drilling at a higher build-up angle, 15° per 100 ft, also offer the potential for reducing the distance between the well spudding point and a point where the well becomes horizontal (Prevedel, 1985).

HORIZONTAL WELL-STEAM FIELD PROJECTS

Table II lists nine horizontal well thermal projects; it shows only four active projects, two with a steam assisted gravity drainage process in Canada, one recently started with cyclic steam in California, and one in Brazil. Presently, the thermal recovery technique used in the Brazilian well is not known (EOR Week, February 5, 1985).

Since 1978, Esso's steam assisted gravity drainage pilot, with a 1000 ft long horizontal production well and vertical steam injection wells, is producing tar sand oil in Cold Lake, Alberta, Canada (see Table II). Baldwin et al., (1983) report that it took about 42 days to drill a 1000 ft long horizontal well. Mainland and Lo (1983) report that from 1978 to 1982, the well produced over 100,624 bbls of oil. Allowing sufficient time for drilling of the horizontal producer and vertical injectors, the average daily production works out to be about 75 bbl/day. This is better than the average daily production rate of 51 bbl/day expected from cyclic stimulation of a vertical well drilled at 4 acre spacing. The vertical well production was calculated by assuming 8 cyclic steam stimulations over a period of 8 years (Mainland and Lo, 1983). Due to the encouraging results of the first pilot, Esso recently announced plans to drill a second 3228 ft long horizontal well in Cold Lake (MacDonald, 1985). The second horizontal well will also be operated as a producer with vertical injectors to obtain steam assisted gravity drainage. In contrast to Esso's success with horizontal wells, other tar sand projects with cyclic steam stimulation and steam drive (see Table II) were discontinued, probably because of poor thermal efficiency. For example, Signal Oil Company's Sunny Side project in Utah gave an SOR (steam oil ratio) of 23 using cyclic steam and steam drive. The limited field results show that steam assisted gravity drainage using horizontal wells offers an efficient method to produce viscous bitumen. This finding confirms the theoretical results of Khosla and Cordell (1985), Jain and Khosla (1985), and Best et al. (1985).

Table II lists three projects for heavy oil production. The first one in California started steam stimulation of a single horizontal hole in early 1986. The horizontal section was drilled from a vertical well using MDHD drilling technique. The initial results are encouraging, but currently production data are not available in the open literature. The second pilot, i.e., HOPCO pilot, included eight laterals, drilled from a 5 ft diameter, 500 ft deep shaft in Kern River field, California. A cyclic steam stimulation of laterals was conducted so that at a given time only two laterals were steamed while other adjacent laterals were put on production (Oil & Gas J., 1982; Rintoul, 1982). California state records show oil production of 7303, 6300, and 6304 bbl per month during January to March, 1985. The project was shut down in April 1985. During the three months of operation, the initial production of 50 bbl/day has increased to 300 bbls/day. Although this production level was near the breakeven point for steam injection, it was only one-half the expected rate at that time (Pace Synthetic Report, March, 1986). The major problem for the low oil production rate was thought to be a well completion method (Allen, 1986). The third pilot in Brazil's Fazenda Belem field reports 75 bbl/day oil production with a 544 ft long horizontal hole in a 30 ft thick pay zone. This is significantly better than adjacent vertical wells producing about 16 bbls/day. However, as noted earlier, the report does not include information about the well operation process (EOR Weekly, February 5, 1985). The above data show one failure and one success for cyclic steam stimulation in an unconsolidated formation. As discussed earlier in the paper, the theoretical results show a high oil recovery with a combination of steam drive and horizontal wells for producing heavy oils. Presently, field data are not available to confirm theoretical results. However, the field pilots, definitely establish the feasibility of drilling, and completing horizontal wells in an unconsolidated heavy oil reservoir.

HORIZONTAL WELL ECONOMICS

Table I shows that in the year 1979-80, the cost of drilling a horizontal hole was about 6 to 8 times more than a vertical well. In the last six years, advances in drilling technology have progressed sufficiently to reduce a long horizontal well cost to 1.5 to 2 times a vertical well cost. The costs could be reduced even further if drainholes are drilled from an existing vertical well, i.e., by using short drainhole or medium length drainhole technology.

A shaft and mine approach for drilling horizontal wells may be economical for very shallow formations (100-200 ft). Although experimental, HOPCO project reports a high capital cost, $8/bbl, for a 500 ft deep mine and shaft project (Oil & Gas J., 1982). Therefore, for most of the field projects, a horizontal well drilled from the surface would be most economical.

Conclusions

The following conclusions were drawn from this study:

1) Various commercial technologies are available for drilling horizontal wells in an unconsolidated formation. Although horizontal wells costs more than vertical wells, they also produce more oil than vertical wells.

2) Theoretical and laboratory experimental data show that the steam-horizontal well combination not only gives higher oil production rates but also gives higher recovery of original oil in place as compared to that obtained using cyclic steam or steam drive with vertical wells.

3) Horizontal wells could be used to reduce steam override. They could also be used to produce from reservoirs with bottom water zones without losing excessive steam to bottom water.

4) Laboratory data, theoretical analysis, and limited field experience indicate that steam assisted gravity drainage using horizontal wells is probably the most suitable process to produce tar sands and bitumen.

5) For heavy oil production with horizontal wells, numerical results show a high oil recovery using steam drive; laboratory data show a high oil recovery using steam assisted gravity drainage. Field data show a mixed success for steam stimulation.

6) More work is needed in the area of horizontal well cementing and completing. At present most horizontal well completions use slotted liners.

7) Numerical simulation data are needed to compare steam drive, cyclic steam, and steam assisted gravity drainage using horizontal wells for producing heavy oils.

8) Reservoirs with continuous shale barriers may not be good candidates for horizontal well drilling.

ACKNOWLEDGEMENTS
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NOMENCLATURE

A Drainage area, acres
h Reservoir height, ft
k Permeability, md

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ALBERTA OIL SANDS
INFORMATION CENTRE

United States Patent [19]
Porter

[11] **Patent Number: 4,460,044**
[45] **Date of Patent: Jul. 17, 1984**

[54] ADVANCING HEATED ANNULUS STEAM DRIVE

[75] Inventor: **Luther T. Porter**, Anaheim, Calif.

[73] Assignee: **Chevron Research Company**, San Francisco, Calif.

[21] Appl. No.: **413,324**

[22] Filed: **Aug. 31, 1982**

[51] **Int. Cl.**^{3} **E21B 36/00; E21B 43/24**
[52] **U.S. Cl.** **166/252**; 166/263; 166/272; 166/50; 166/191
[58] **Field of Search** 166/263, 272, 50, 250, 166/252; 299/2

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Primary Examiner—Ernest R. Purser
Assistant Examiner—Mark J. Del Signore
Attorney, Agent, or Firm—G. W. Wasson; L. S. Gruber; Edward J. Keeling

[57] ABSTRACT

A method is disclosed for producing viscous petroleum from subsurface deposits. The method employs a vertical well and a horizontal well through the petroleum deposit. A combination of injection procedures through the horizontal and vertical well heat the viscous petroleum in the annulus around the horizontal well. Successive completion intervals are installed in the horizontal well to produce the heated petroleum. The petroleum is driven by a drive fluid passing through previously produced intervals.

14 Claims, 8 Drawing Figures

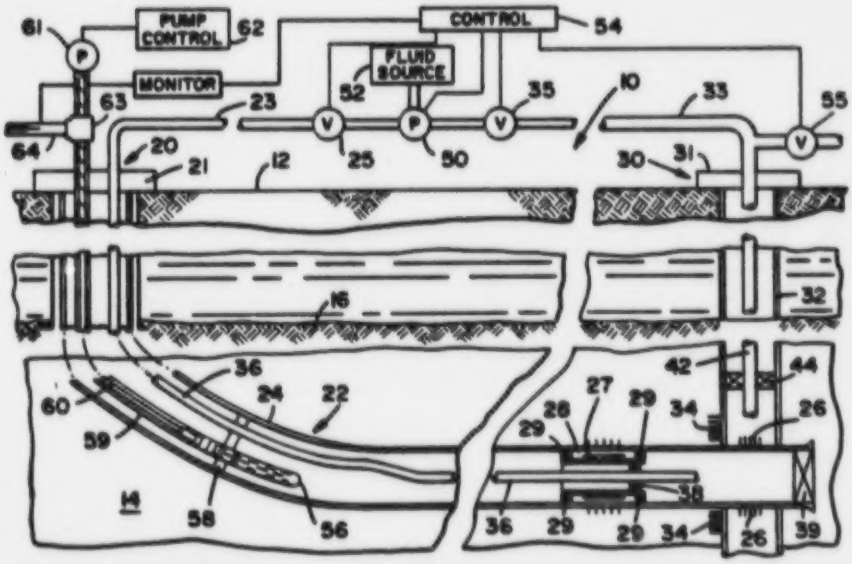
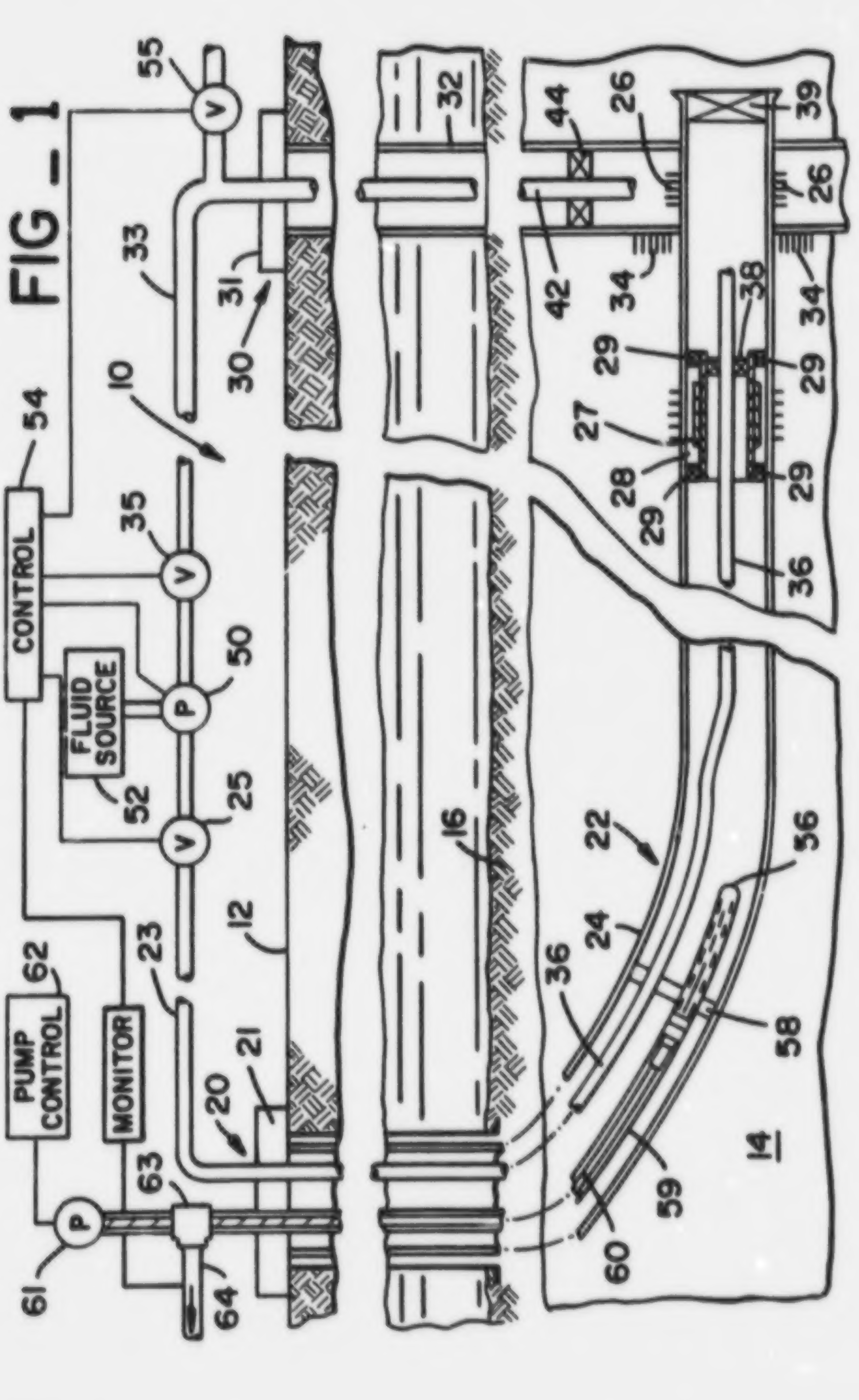


FIG_1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FLUID SOURCE
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PUMP CONTROL
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UNITED STATES PATENT AND TRADEMARK OFFICE

CERTIFICATE OF CORRECTION

PATENT NO. : 4,460,044
DATED : July 17, 1984
INVENTOR(S) : Luther T. Porter

It is certified that error appears in the above-identified patent and that said Letters Patent are hereby corrected as shown below:

Claim 9, Col. 8, line 2, "ahd" should read --and--.

Signed and Sealed this

Fifteenth Day of *January 1985*

[SEAL]

Attest:

GERALD J. MOSSINGHOFF

Attesting Officer ***Commissioner of Patents and Trademarks***

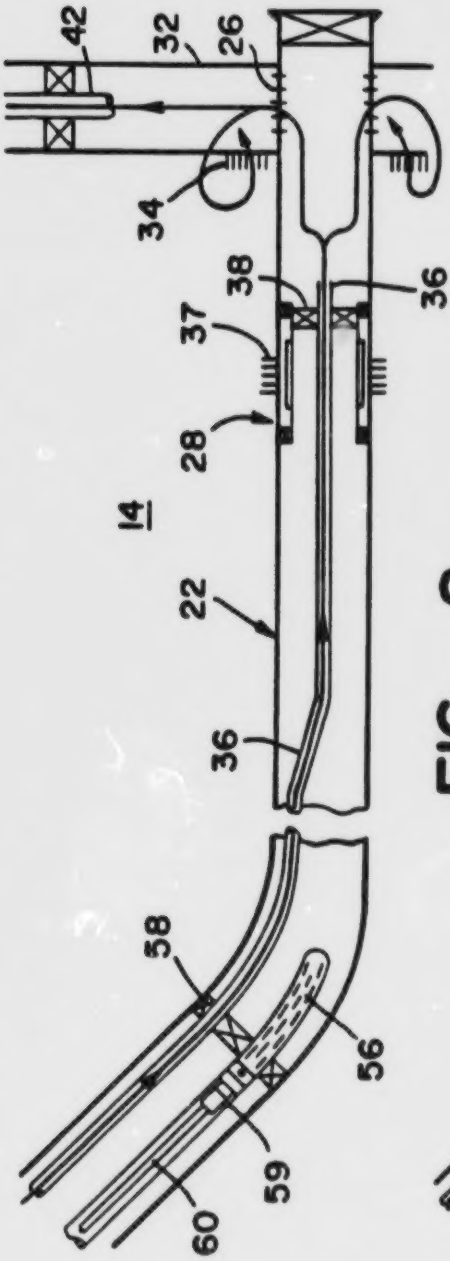


FIG – 2

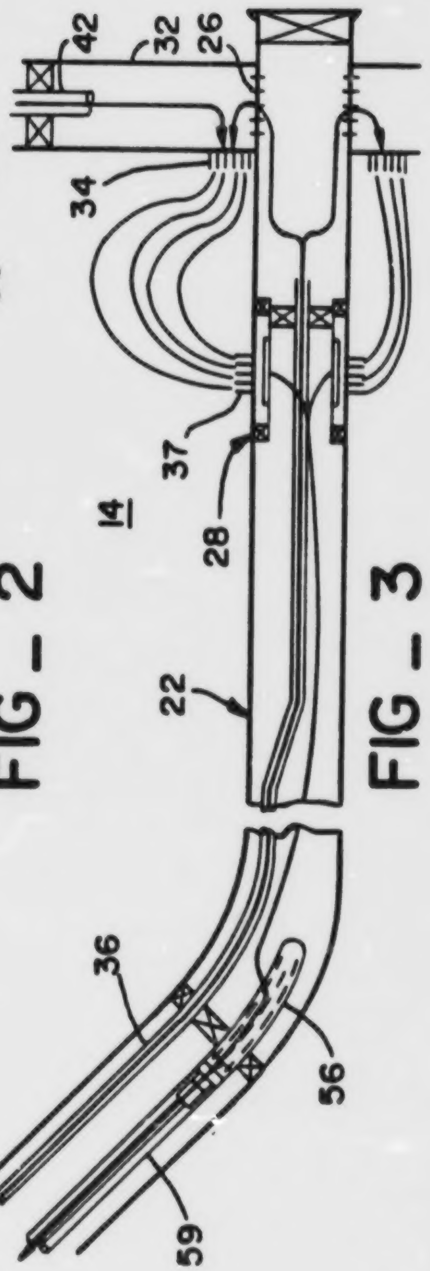
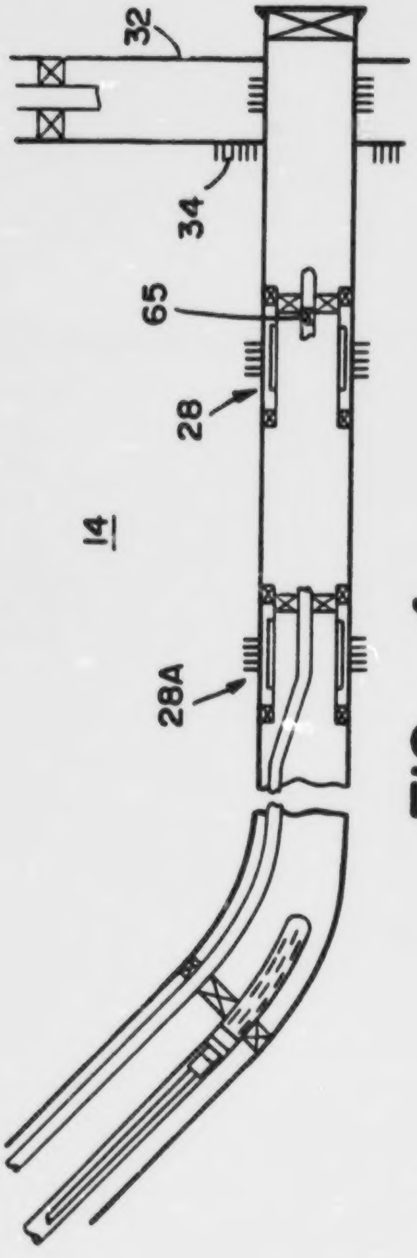


FIG – 3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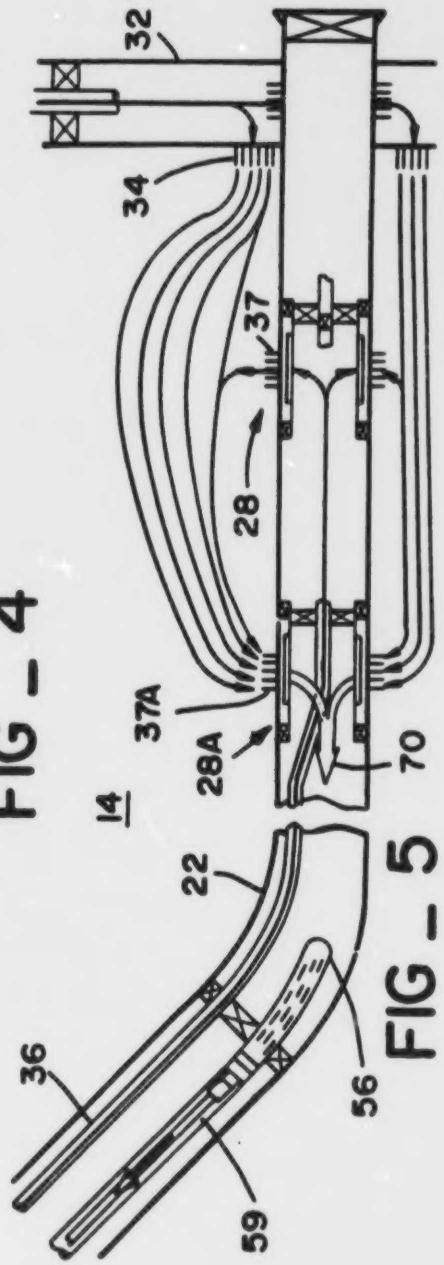
28A

FIG_4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37A
28A
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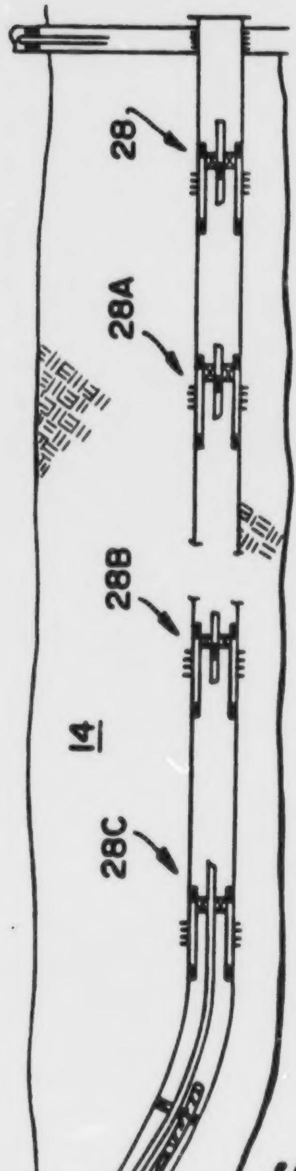
FIG_5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28A
28B
28C
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FIG_6

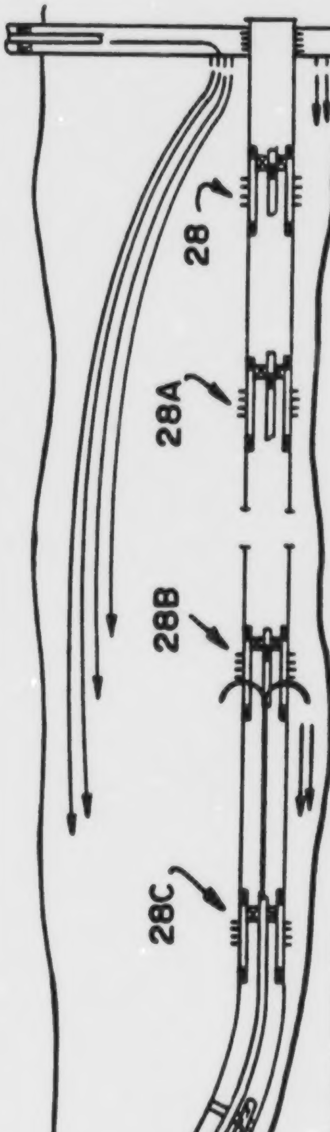
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FIG_7

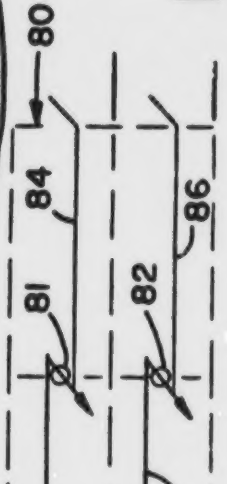
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FIG_8

ADVANCING HEATED ANNULUS STEAM DRIVE

BACKGROUND OF THE INVENTION

This invention relates to a method and apparatus for the recovery of highly viscous petroleum from a tar sand, heavy oil sand, or other subsurface permeable formation containing viscous petroleum deposits. The method is performed using a well formed and completed substantially horizontally through the formation containing the highly viscous petroleum and an adjacent substantially vertical well in cooperating alignment with the horizontal well. The method is an improvement of a prior art method making use of a horizontal perforated casing positioned within the petroleum formation. An example of that method is found in U.S. Pat. No. 4,368,781, issued to Donald J. Anderson for Method of Recovering Viscous Petroleum Employing Heated Subsurface Perforated Casing Containing a Movable Diverting Means and assigned to the same assignee as the present application. The method of the present invention provides for more efficient fluid flow paths for injected drive fluids and produced fluids.

PRIOR ART

In the prior art method initial production is made possible by conduction heating from a horizontal well. When the heated formation has developed a zone of increased fluid mobility due to conduction heating, a steam drive of the movable petroleum is initiated. The steam drive causes the petroleum to move along the heated annulus at the exterior of the horizontal well. Injected steam and produced fluids are directed and channeled in such a manner that previously swept zones may be resaturated with movable petroleum, or, in the event of a steam drive breakthrough, the injected steam bypasses the heated petroleum leaving it in place in the formation.

BRIEF DESCRIPTION OF THE PRESENT INVENTION

The present invention involves the drilling and completion of a horizontal well in a heavy oil or tar sand reservoir. A vertical steam injection well is drilled in close proximity to the underground end of the horizontal well, preferbly within 15 to 20 feet. The horizontal portion of the horizontal well preferably extends about 1000 feet through the heavy oil or tar sand reservoir.

The vertical steam injection well is perforated adjacent to the underground end of the horizontal well. Likewise the horizontal well is perforated adjacent to the underground end of the steam injection well. Necessary sand control measures are taken and fluid flow communication is established between the two wells. Next, the horizontal well is completed through a first interval of the reservoir.

A completion interval at some distance, about 200 to 400 feet, from the vertical steam injection well is isolated with an internal permeable well completion section. The horizontal well is then dual completed as a producer and steam injector. Hot fluid is then circulated through the annulus of the horizontal well to heat the reservoir around the well. Eventually the formation around the horizontal well and adjacent to the injection well becomes heated enough to permit the hot fluid to flow out through the perforations in the horizontal well, into the formation, into the vertical injection well and up the injection well to the earth's surface. Continued

injection causes the viscous fluids near the underground end of the horizontal well to become heated thus increasing their mobility due to reduced viscosity and eventually the viscous fluids are produced at the injection well and into the annulus of the horizontal well through the internal permeable well completion section.

The production at the wellhead of the injection well and the horizontal well is monitored and, at such time in the process when fluid production is well established in the horizontal well, the hot fluid injection through the horizontal well is discontinued and the injection of hot fluids through the injection well provides the hot fluids to both heat the formation and to move the viscous fluids into the horizontal well. When the hot fluid drive has progressed to the point of drive fluid breakthrough into the horizontal well production side, the horizontal well will be recompleted at another interval along the well. The well perforations in the previously completed interval of the horizontal well nearest to the injection well are then plugged off by means of a tubing plug at or near the packer. The horizontal well is then recompleted at some distance away from the old completion interval.

The production/injection equipment is then rerun into the horizontal well, and production is reinstated by conduction heating and hot fluid drive as previously done in the first production in the horizontal well.

This process of completing, producing, interrupting and recompleting proceeds along the horizontal well until substantially all recoverable viscous petroleum has been produced.

OBJECTS OF THE INVENTION

The object of the present invention is a method for producing viscous petroleum from subsurface deposits in an efficient and practical manner.

Another object in accord with the preceding object is a method for completing and operating well elements in a subsurface well to cause viscous petroleum to move into the well elements and to be transported to the surface above the well.

Further objects and features of the present invention will be readily apparent to those skilled in the art from the appended drawings and specification illustrating a preferred embodiment wherein:

FIG. 1 is a sectional view through a subsurface earth formation illustrating surface and subsurface elements of the present invention.

FIGS. 2-7 are sectional views through the subsurface portion of wells and the surrounding earth formation as illustrated in FIG. 1 and showing progressive operation of the method of the present invention through the subsurface elements.

FIG. 8 is a schematic plan view of the method of the present invention operating several production wells with relationship to injection wells.

DETAILED DESCRIPTION OF THE INVENTION

FIG. 1 is a cross-sectional view through an earth formation illustrating a representative form of apparatus which may be used to perform the method of the present invention. As illustrated, the earth formation 10 generally includes a portion referred to as the earth surface 12 and the subsurface petroleum containing formation 14 with the additional earth formations separating the earth surface from the subsurface formation generally terminating in an impervious area 16 above the petroleum-containing formation. The formation containing the petroleum for which the present invention is particularly applicable is frequently characterized as a tar sand or a formation containing heavy viscous crude oils without sufficient natural drive to cause the petroleum to be producible through conventional geopressure drive or from conventional pumping techniques. Further, the formations for which the present invention is of particular interest, are those formations which are at a depth in an earth formation that would preclude the possibility of surface mining. The viscous petroleum of interest is that contained within the formation which is responsive to techniques that will cause its viscosity to be improved such that it becomes mobile and can be moved through the formation into suitable producing channels.

In the specific apparatus herein illustrated the first well 20 is drilled into the surface formations and through the impervious barrier 16 and then slanted into the formations to produce a wellhead 21 and a substantially horizontal well 22 having casing 24 passing horizontally through the formations. A second well 30 is drilled through the surface earth formations and into the petroleum-containing formation 14 and completed with a wellhead 31. Well 30 remains substantially vertical throughout its entire length and is completed into the subsurface formations with a casing 32.

The bottom hole end of the horizontal well 22 and the bottom hole end of the vertical well 30 are terminated in close proximity to each other, preferably within 15 to 20 feet of each other in the formations. Both wells are initially perforated at or near their downhole end to establish perforations 26 in the horizontal well and 34 in the vertical well. The horizontal portion of the horizontal well in the petroleum-containing formation preferably extends about 1000 feet through the formation 14.

The horizontal well, near to the vertical well 32 is completed with a casing liner 28 having packers 29 at each end and a producing interval at 27 which may be a wire-wrapped screen or a perforated gravel pack. The downhole end of the horizontal well is then completed with an injection tubing 36 passing through a packer 38 in the subsurface completion 28 to extend into the downhole end of the horizontal well to provide access to the well below the completion. The end of the horizontal well 22 is sealed with a packer or cement plug 39.

The vertical well 30 is completed with an injection tubing 42 passing through a packer 44 and into the downhole end of the vertical well for communication with perforations 34.

Tubing 36 in the horizontal well is completed through the wellhead 21 of well 20 and is connected through surface tubing 23 and valve 25 to a pump 50. In like manner, the tubing 42 of the vertical well 32 is completed through wellhead 31 and through surface tubing 33 to a valve 35 also in contact with the pump 50. A fluid source 52 is connected through the pump 50 and valves 25 and 35 to provide subsurface fluids to the horizontal well 22 and vertical well 32, respectively, all under the control of a suitable control device 54 which provides not only control for the fluid source 52 but also for valves 25 and 35 and an additional valve 55 which function will be described later on.

In FIG. 1 a second completion is illustrated in the horizontal well providing a producing element at 56 which may be a sucker rod pump or other type of pump positioned in dual tubing hanger 58 and connected to the wellhead 21 through tubing 59 which may contain the sucker rods 60 from a surface pump 61 under the control of pump control 62. The tubing 59 is adapted with a packing gland 63 to permit production to be passed through a suitable gathering piping 64.

FIGS. 2–8 illustrate a series of steps that may be performed with the apparatus of the present invention to accomplish the desired method of maximizing the production of the viscous crude from the earth formation in an efficient manner. In a tar sand or a heavy oil reservoir there may be little or no primary oil production. To produce the desirable oil, the formation adjacent to the production well, here shown as the horizontal well, is first heated by circulation of a hot fluid in the horizontal portion of the well to heat, by conduction, the formation surrounding the well. FIG. 2 illustrates the anticipated path of the hot fluids or steam down through the injection tubing 36 and into the downhole end of the horizontal well. The fluid is circulated through the tubing within the horizontal well 22, through the completion interval 28 which is isolated by the thermal packer 38, through the interval of the horizontal well between the completion interval 28 and the bottom end of the well, out the perforations 26 adjacent to the vertical injection well 32, and into the injection well through perforations 34 to then progress up and out of the steam injection well through the wellhead 31 and conductor 33 to be monitored at the control 54. The path of the hot fluid injection is shown by the darkened lines and the arrows running through the tubing 36 and upwardly through the vertical well 32. During this heating/injection operation, back pressure is held on the steam injection well such that the downhole pressure does not exceed the formation fracture pressure so as not to cause the formation to be separated or parted.

As soon as the viscous fluids near the horizontal well annulus become heated, their mobility will be increased, due to reduced viscosity, and these hydrocarbons will be produced into the injection well 32 along with the hot fluids. The production of such crudes can be monitored by the control 54 to determine when the viscous crude has become sufficiently mobile to establish reasonable production from the subsurface formation. At that time the production of hot fluids and hydrocarbons is discontinued in the injection well 32 and the flow of formation hydrocarbons is then reversed from flowing into the perforations 34 in the vertical well to flowing into the perforations 37 at the well completion interval 28 and through those perforations into the screen 27 and into the annulus inside of the horizontal well 22. As soon as productions of hydrocarbons begins into the horizontal well 22, injection of steam or hot fluids is started in the injection well 32. Sustained flow of formation hydrocarbons into the well completion interval 28 through perforations 37 is under the force of the continued injection of steam or hot fluids from the horizontal well 22 injection tubing 36 and the vertical well 32 injection tubing 42.

As illustrated in FIG. 3, the production of viscous petroleum from the formation 14 is driven by whatever steam injection is maintained from the horizontal well 22 and from the steam injection from the vertical well 32 to cause the petroleum to flow into the completed portion of the well at 28. Steam injection from the horizontal well may be terminated leaving only the drive from steam injected through the vertical well. The mobile petroleum flows through the sucker rod pump or othr pump 56 and upwardly to the earth surface through tubing 59.

During this drive of the mobile petroleum, the steam is provided from the vertical injection well 32 and the pressure on that steam is such as to maintain a constant pushing force on the heated petroleum. When the steam drive has progressed to the point of a steam breakthrough into the horizontal well production side, the steam injection is temporarily terminated in the vertical well, the injection and production elements are withdrawn from the horizontal well, and a new completion interval is established in the horizontal well as illustrated in FIG. 4. Prior to establishing the new completion interval, a plug 65 is installed in the injection tubing 36 at the completion interval 28 so as to prevent any injection fluids from flowing through the previous completion and into the lower end of the horizontal well.

The new completion within the horizontal well is spaced along the horizontal well, a reasonable distance, for instance 300 to 600 feet, from the previous completion and a new completion interval 28A is established with duplicated packers, screens, and perforations as was established in the first completion interval 28. Prior to placement of the new completion interval, the production equipment is withdrawn from the well to permit the new equipment to be placed into the well and, when the completion is established, the production equipment is rerun into the horizontal portion of the well in the form as illustrated in FIG. 4. As illustrated in FIG. 5, the hot drive fluid is pumped through the injection well 32 and through the perforations 34 therein along with the fluids pumped through the injection tubing 36 to pass through the second completion interval 28A and in a reversed direction through the screen and perforations 37 of the first completion interval 28. The heavy viscous petroleum in the formation 14 is heated and pushed by the injection fluids and produced through the perforations 37A and completion interval 28A into the annulus of the horizontal well 22 as shown schematically by arrow 70. The production flows into the sucker rod pump or other type pump 56 and upwardly through the producing tubing 59.

Initial steam injection into the formation is possible due to the reservoir voidage and heating created by the production of viscous crudes during the completion as illustrated in FIGS. 2 and 3. The production response in this second completion will be expected to be more rapid than in the first completion since the residual heat energy will exist in the reservoir because of the initial steam injection through the horizontal well during the first production. Because of this residual heat and fluid mobility the distance between the second completion 28A and the first completion 28 can be increased over the distance that was required between the first completion interval 28 and the injection well 32.

FIGS. 6 and 7 illustrate the final phases of a continuing production/steam drive after several recompletions and advancement of the steam drive front through the formation 14. As here illustrated, four separate recompletions (28, 28A, 28B and 28C) of the horizontal well have been established with each completion separated from the previous completion by a greater distance for the reasons described in the previous paragraph. While four completions are illustrated, it should be understood that this is merely representative of any plurality of completions. In each of these intervals the volume, temperature and the pressure of the hot fluid or steam injected via the horizontal well can be varied to avoid excessive heat losses to produced fluids. As should be expected, the horizontal well steam injection should be discontinued in each phase when significant steam condensate is produced. Production of steam condensate indicates that a path of high fluid mobility along the horizontal well annulus has been achieved and that fluid saturations have changed adequately for sustained production for the duration of the steam drive in that particular operation. The ratio condensate to produced formation fluid can be monitored at the production conductor 64 with a signal from this monitor provided to the control 54 to control over the fluids supplied through conductors 23 and 33 to the subsurface portions of the wells 22 and 32.

Previous proposals for the recovery of significant percentages of the petroleum in place in tar sands and other very high viscosity heavy oil reservoirs have required very close vertical well spacings. The typical proposals use a 2.5-acre, 5-spot or similar pattern, such as in a closely spaced 7-spot pattern. Prior proposals with regard to heated annulus horizontal wells have proposed a large number of vertical wells at very close spacing, for instance 100 to 300 feet between wells.

In the present proposal, the advancing heated annulus drive of producing viscous crudes, most of the vertical wells are eliminated thereby greatly improving the development economics. It is known that horizontal wells can be drilled extending in substantial long horizontal directions, for instance, wells have been drilled as much as 1000 feet in a horizontal direction from a vertical well. In that regard a single injection well may function to drive fluids into one or more horizontal wells which may be spaced in a variety of geometric patterns around the injection wells. FIG. 8 is a typical schematic illustration used by petroleum engineers to indicate the positioning of injection and production wells. As here illustrated in the production block 80 a pair of injection wells 81 and 82 are illustrated in the cooperating alignment with horizontal production wells 83, 84, 85 and 86. In the form illustrated each of the steam injection wells serves two horizontal wells. This pattern in spacing is superior to previous proposals in that fewer wells are needed to deplete a given subsurface formation volume. While not specifically illustrated, the present invention can be employed with other producing wells drilled into and adjacent to the horizontal well.

Throughout this specification the injection fluid has been referred to as fluid or steam. It should be understood that it is intended to include in such fluids, steam, solvents gases, and mixtures of such fluids that will be effective in heating, displacing and driving viscous petroleum through the subsurface formations.

While certain preferred embodiments of the invention have been specifically disclosed, it should be understood that the invention is not limited thereto as many variations will be readily apparent to those skilled in the art and the invention is to be given its broadest possible interpretation within the terms of the following claims.

What is claimed is:

1. A method for assisting the recovery of viscous petroleum from a petroleum-containing formation comprising:

(a) forming and completing a substantially horizontal well through said petroleum-containing formation;

(b) forming and completing a second well having a portion thereof in close proximity to the subsurface end of said substantially horizontal well;

(c) perforating a portion of said substantially horizontal well near the subsurface end thereof adjacent to said second well;

(d) perforating a portion of said second well at said portion thereof in close proximity to said subsurface end of said substantially horizontal well;

(e) placing a packer and injection tubing in said substantially horizontal well near the subsurface end thereof, said tubing and packer being adapted to permit a first fluid to be injected through said substantially horizontal well and out said perforations therein;

(f) placing a packer and injection tubing in said second well, said packer and tubing being adapted to permit fluids to flow into or out of said tubing and said second well through said perforations therein;

(g) injecting said first fluid through said tubing in said substantially horizontal well, through said perforations therein, and into said second well through said petroleum-containing formation;

(h) monitoring the fluid produced from said second well to identify said first fluid and petroleum produced from said formation, said monitoring including identifying the ratio between said first fluid produced and said petroleum produced as well as the pressure of fluids in said second well;

(i) based on said monitored ratio and said producing pressure, injecting a second fluid through said tubing in said second well, through said perforations therein into said formation and through said formation into said substantially horizontal well;

(j) and producing said viscous petroleum and said fluids through said substantially horizontal well.

2. The method of claim 1 wherein said production of viscous petroleum into said substantially horizontal well is through a completion interval in and laterally along said substantially horizontal well away from said subsurface end thereof.

3. The method of claim 2 wherein said injection of said first fluid through said tubing in said substantially horizontal well and into said second well heats said petroleum-containing formation, and said injection of both said first fluid and said second fluid injected through said tubing in said second well moves said viscous petroleum in said heated petroleum-containing formation into said completion interval in said substantially horizontal well.

4. The method of claim 1 or 3 wherein produced fluids from said horizontal well are monitored for the ratio of said first and said second injected fluids to produced viscous petroleum fluid and, based on a predetermined ratio of said monitored fluids produced into said completion interval of said substantially horizontal well, changing said injection of said first fluid through said tubing in said substantially horizontal well while continuing injection of said second fluid through said tubing in said second well.

5. The method of claim 4 wherein said produced fluid through said completion interval is monitored for the ratio of produced viscous petroleum to said first and said second injected fluids and, based upon a predetermined monitored ratio, interrupting said injecting of said first injected fluid, plugging said tubing through said packer near the subsurface end of said substantially horizontal well and severing said plugged tubing from said remaining tubing, then placing a second packer in said substantially horizontal well along said remaining tubing and completing said substantially horizontal well at said second packer to isolate said substantially horizontal well below said plugged packer from said substantially horizontal well above said second packer, and reinitiating injection of said first injection fluid, said completion in said remaining tubing at said second packer being adapted to permit fluids to be injected through said substantially horizontal well and into said petroleum-containing formation through said previous completion interval,

and producing said viscous petroleum and said injection fluids through said completion interval at said second packer in said substantially horizontal well.

6. The method of claim 5 with the production of viscous petroleum at successive completion intervals at spaced locations axially along said substantially horizontal well away from said subsurface end and spaced from successively plugged tubing severed from said injection tubing at packers in said substantially horizontal well.

7. The method of claim 6 wherein successive completion intervals are spaced increasing distances from each other at said spaced locations axially along said substantially horizontal well.

8. A method of assisting the recovery of viscous petroleum from a petroleum-containing formation comprising:

(a) forming and completing a substantially horizontal well through said petroleum-containing formation;

(b) forming and completing a second well having a portion thereof in close proximity to the subsurface end of said substantially horizontal well;

(c) injecting a hot first fluid through said substantially horizontal well and into said second well in a manner to cause said viscous petroleum adjacent to said horizontal well and said second well to become mobile;

(d) establishing a first completion interval in said substantially horizontal well near the subsurface end thereof;

(e) injecting a second fluid through said second well to cause said heated viscous petroleum to flow into said substantially horizontal well at said first completion interval;

(f) monitoring said produced viscous petroleum and said first and said second injected fluids and, based on a predetermined ratio, converting said first completion interval to an injection interval for injection of hot fluids into said petroleum-containing formation;

(g) establishing a second completion interval in said substantially horizontal well spaced from said converted first completion interval and said second well;

(h) and continuing injection of said second fluid through said second well and injection of said hot first fluid through said converted first completion interval to cause said heated viscous petrolum to flow into said substantially horizontal well at said second completion interval.

9. The method of claim 8 with the production of viscous petroleum ahd injected fluids at successive completion intervals at axially spaced locations along said substantially horizontal well away from said subsurface end, each successive completion connecting the previous completion to an injection interval.

10. The method of claim 1 or 8 wherein said injection fluid includes steam, solvents, gases, and mixtures

thereof to heat, displace and drive said viscous petroleum through said subsurface formation.

11. The method of claim 4 wherein said change of injecting said first fluid is a change in the rate of injecting said first fluid.

12. The method of claim 4 wherein said change of injecting said first fluid is a change in temperature of injection of said first fluid.

13. The method of claim 4 wherein said change in injecting said first fluid is a termination of injecting said first fluid.

14. The method of claim 4 wherein said change in injecting said first fluid is a combination of changes in rate of injection and temperature of injection of said first fluid.

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Editors

Chapter 94

EVALUATION OF BITUMEN RESOURCE DEVELOPMENT UTILIZING HORIZONTAL WELLS DRILLED FROM THE SURFACE OR FROM UNDERGROUND TUNNELS

C.T. Horkoff

INTRODUCTION

The four major oil sands deposits in Alberta, Canada cover an area in excess of 4 million hectares in the Athabasca, Wabasca, Peace River, and Cold Lake regions and have reserves of oil in-place of more than 145 billion cubic meters. The Athabasca deposits are estimated to contain 110 billion cubic meters of crude bitumen, of which 90 percent are at depths that must be recovered through in-situ recovery techniques.

The majority of in-situ recovery testing has utilized vertical wells drilled from the surface. Cursory examination suggests that horizontal well systems may have economic advantages over systems utilizing only vertical wells. A feasibility and pilot preplanning study (the Surmont Project) was undertaken to determine the viability of using horizontal well systems for recovering bitumen from the Athabasca deposits by in-situ methods. Two distinctly different modes of access were evaluated: (1) surface, and (2) shaft and tunnel, such that comparisons can be made with vertical well systems.

OBJECTIVES AND BENEFITS

The objective of the Surmont Project is to determine the technical, economic, and environmental feasibility of recovering bitumen from oil sand formations with a system of horizontal wells utilizing in-situ steam methods. Two means of access to the formation will be considered: the drilling of wells from the surface, which will be deviated to the horizontal plane, and the drilling of wells from tunnels placed above, within or below the pay zone.

In comparison to vertical wells from surface, it is felt that horizontal well systems offer the potential benefits of a more cost-effective production scheme, significantly improved recovery of the resource, and a reduction in the environmental impact upon the development area.

IMPLEMENTATION: GENERAL BACKGROUND

To accomplish the project objectives, Gulf Canada Resources (GCRI) and the Alberta Oil Sands Technology and Research Authority (AOSTRA) entered into an agreement on September 27, 1979 to carry out the project jointly. Gulf Canada Resources was designated the operator, with AOSTRA's continual input and retrieval of information ensured. The intent was to operate in a mode of reciprocity with equal input of ideas and financial and natural resources.

The individual programs, general project direction, and project organization were developed by a task force of six members. Three members each from GCRI and AOSTRA prepared the programs and cost estimates that became the basis for the letter of agreement.

The natural resources commitment was displayed in the allocation of bitumen resources by both parties. Four sections of land were initially designated for the pilot site—two committed by AOSTRA and two by GCRI. The AOSTRA lands are located in Sections 4 and 5 in Township 84 Range 6 W4M. The GCRI lands are part of Athabasca oil sands lease covering Sections 32 and 33 in Township 83 Range 6 W4M. The ideas commitment and a system to provide GCRI's and AOSTRA's continual input and retrieval of information are reflected in the organization.

PROJECT PHASES

The Project was divided into two distinct phases, A and B, to provide both Gulf Canada Resources, Inc. and the Alberta Oil Sands Technology and Research Authority with major decision point in the overall project.

Phase A is the prepilot and pilot feasibility design study phase. Activities to accomplish this included:

- Pilot site confirmation and access.
- Technical, economic, and environmental feasibility studies.
- Prepilot planning to define scope of experimentation and of activities.
- Cost estimates development for pilot construction and operation.

The specific phase A programs were:

1. Building a 24 kilometer access road from Anzac to the pilot site.
2. Drilling up to ten vertical wells to prove up the project site.
3. Implementing a geotechnical and geophysical

program necessary for the design and building of shafts and tunnels.

4. Developing a process numerical simulation system for horizontal well configuration assessments.
5. Designing the shaft and tunnel systems for underground drilling and production access.
6. Designing underground drilling and production systems to investigate horizontal well performance of different configurations using steam as the drive medium.
7. Designing the drilling of wells from surface that are deviated to the horizontal.
8. Designing surface facilities to accommodate the services required for each production system.
9. Assessing and designing the environmental programs required to receive permission to pilot.

Phase A costs and timing are:

1. Completion of the project phase within a total cost of 9.8 million dollars.
2. Report target date of December 1, 1993.

Phase B is the pilot construction and operations phase, and consists of:

1. Construction and operation of the pilot for a period of 11 years.
2. Testing of the assumptions developed during phase A as well as evaluating results during the pilot period.
3. Providing general conclusions (in addition to site specific results) in a final project report by December 31, 1993.

DESIGN CONSIDERATIONS

All pilot options raised were tested against technical, economic, and environmental standards developed by the project staff and consultants. Technical feasibilities and related sensitivities assessments were undertaken for the key operating entities in the form of paper studies. Economic feasibilities were based on projecting commercial operations and running economic sensitivity studies. Environmental matters were assessed by projecting environmental study parameters to commercial operations.

Results of the technical, economic, and environmental analysis identified that the priorities for piloting are directed to process matters, well completions, and drilling systems. Other elements of the production chain, such as underground access, underground production systems, and surface facilities, would be tested as a further extension of the pilot but only after processing, well completions, and drilling systems were assessed. As such, the design of the pilot would be directed to production and closely related operations, while the other items will be designed, built, and operated with "greater reliability" in mind. The underlying philosophy of this effort would be to have a high on-line-time reliability for most of the production chain and thus provide a better opportunity to fulfill the long range pilot efforts. The economic and environmental elements projected to commercial operations reflect that surface access horizontal well systems and shaft and tunnel access horizontal well systems are economically based on the assumptions available to the project. In addition, comparisons made to date against vertical well systems suggest that both surface access and shaft and tunnel access horizontal well systems can give substantial contributions to the project.

The emphasis toward the process, completions, and drilling pilot activities is displayed in the list of parameters that will be the basis for experiments during phase B. These areas to be tested are:

1. Surface access systems versus shaft and tunnel access systems.
2. Well spacing.
3. Reservoir parameter differences.
4. Well lengths.
5. Different processes.
6. Three different completions techniques.
7. Three different modes of drilling.
8. Well system orientations.

The number of experiments to provide a reasonable basis for conclusions resulted from an analysis of the number of variables to be examined compared to the number of variables that had to remain constant. The repeatability and reliability of information was also a consideration in the "experimental design," to enhance the possibility of forming general conclusions rather than site-specific conclusions. These were then cost-compared to reflect the cost associated with obtaining information, to place a dimension of incremental cost versus incremental data in perspective.

The repeatability and reliability of information of well performance was addressed by developing "experimental clusters" of five wells. These clusters were to provide the environment that would have three completely enclosed producing wells during a steam stimulation process and two completely enclosed producing wells during a steam flood process.

The number of wells required to develop the drilling and completions operating knowledge, implementation technique, and cost information that can be with reasonable confidence extrapolated to commercial is approximately ten for a similar access mode. Thus, ten wells are required for the surface access mode, *and* an additional ten wells are necessary for the underground access mode. A detailed study of individual elements that make up a pilot, and that can be extended to commercial production, resulted in the following "lists" of items that became the basis for our experimental design.

Process:

1. The steam flood process is economic if well spacing falls with the span of 31 to 62 meters. Recoveries of in the order of 40 to 50 percent appear reasonable.

2. The steam stimulation process is economic for wider well spacings (62 to 93 meters). Recoveries tend to be somewhat less than 50 percent if this process is used for the life of the development.

3. A single well steamflood process has a high recovery; however, production is not evident until after some 13 years of operation. Because of this, this process was not recommended as the first part of the pilot scheme.

4. An approximate horizontal fracture is mandatory to realize the production profiles projected. If a horizontal fracture cannot be developed, then results will reflect an uneconomic situation.

5. The process that appears to be best is a combination of steam stimulation until communication between wells is realized, followed by steamflood, and optimized thereafter after by pressure cycling. In all instances, horizontal fractures are a requirement. Process conditions must be designed to assure that horizontal fractures will be developed.

Completions

1. The optimization of completions is a "trade-off" between sand control, which if not adequate will reduce production output, and pressure drop across completions, which reduces the effectiveness of energy input to the reservoir.

2. The following mechanisms for completions will be checked to determine the best method for optimizing production: gravel pack, slotted liner/screen, and slotted liner only.

3. Open-hole completions are considered too great a risk because of the tendency for tar sands to converge. This was not a valid option to our pilot.

4. Other exotic packing mechanisms will not be piloted because they involve an extension of technology past gravel pack. Should gravel pack systems appear to work best, an extension to pilot work may be to evaluate other packing mechanisms.

Drilling

Two methods of drilling horizontal wells from surface were evaluated: specifically, vertical spud and slant spud. The preference at this time is for a vertical spud method because of lower drilling costs and existing equipment to handle vertical stands operations. The possible disadvantage of this operation is excessive deviation rates required to turn wells to the horizontal, which could cause "key seating." The slant spud case is considered backup at this time.

Underground drilling methods include the in-hole motor, the rotary, and the flexo-drill.

Different drilling methods would be evaluated in a prototype situation before actual drilling in a shaft or tunnel environment would be undertaken. Economic evaluations reflect that the major incentive to shaft and tunnel access is the reduced drilling costs as a result of less drilling through nonproductive soils. The pilots would be designed to drill enough wells by different modes while still accomplishing the process and completions objectives to be able to project commercial conditions with confidence.

Underground Production Systems

In-well horizontal pump installations reduced the online time reliability. The underground production systems have been designed to locate pumping from the "in-well" to the wellhead area. Related production facilities reflect this effort.

For surface access wells, detailed assessments will be made on the merits and demerits of pumps in the horizontal sections, pumps in the vertical section only, and no pumps. For the steam stimulation process it appears that pumping will be required for surface access wells.

Tunnel Level Decision

The project continued to carry the possibility of tunneling in three separate horizons: specifically, above, within, and below the McMurray Formation. The priorities of piloting directed to process matters, well completions, and drilling systems resulted in the need to choose the best level for the pilot operations. Detailed analysis revealed that because of the uncertainty of the impact of steaming operations on soil conditions, the "safest" level for tunneling is in the Devonian. All other functions and factors were evaluated and found to be of lesser importance than the potential impact of steaming.

PILOT OPTIONS

Those elements that should be field tested on a priority basis were clustered into pilot operations. The number of experiments and characteristics required to test the elements are given in table 94–1.

GENERAL DESIGN/DIMENSIONS

The experiments will be located within the 2 1/4 sections allocated to the pilot site. The layout is designed to ensure that steaming operations do not encroach upon the areas where shaft and tunnels will be located, that the bitumen is of sufficient quantity and quality to pilot, and that there is enough surface area for adjusting or expanding the pilot if it is deemed necessary to do so later in the pilot life. In addition, locations of the experiments were considered with the adjoining pilot operations in mind. It was necessary to assure distances were great enough so as not to experience any interference between these different pilots.

Detailed assessments of shaft and tunnel designs and related sensitivities has resulted in the following "key dimensions":

Table 94–1. *Number of experiments and characteristics of cases*

Case Description	A	B	C	D
Number of Experiments	2	4	7	10
Reservoir characteristic changes	x	x	x	x
Surface access—shaft and tunnel access system comparisons	x	x	x	x
Well spacings		2x	3x	3x
Well lengths		2x	2x	2x
Different processes			2x	2x
Well system orientations completions/drilling*			2x	5x

*Most significant parameter to be tested only.

- Shaft inside diameter—3 meters.
- Tunnel inside diameter—3 meters.
- Well spacings from underground—31 meters, 62 meters, and 93 meters.
- Well lengths in pay zone—157 meters and 314 meters.
- Tunnel length—1,415 meters.
- Tunnel depth below oil sand—50 meters.
- Minimum buffer zones between experiments—235 meters.
- Minimum buffer zones between shaft and experiments—314 meters.

The production facilities would be installed in the drill chambers to provide the necessary access for maintenance and monitoring.

Pilot Design

After thorough evaluation of options, it was determined that the minimum number of experiments that must be undertaken to provide comparisons of the most sensitive parameters is four. The maximum number of experiments required to provide all the process, completions, and drilling data to evaluate success of horizontal well systems with two different methods of access is seven. The experiments would be sequenced in a manner that could accommodate the minimum number of experiments and could then be extended to the maximum seven experiments.

By considering technical risk, financial risk, and transfer of technology within the pilot, the pilot construction and operation phase was divided into three distinct stages (B-1, B-2, B-3) to provide two major division points for the project. Their key characteristics are listed below.

For B-1:

- Two surface access (SAC) experiments.
- Surface production and steam generation facilities.
- One 3-meter diameter shaft, 390 meters deep.
- Design, construction, and testing of an underground drilling rig.

For B-2:

- A second 3-meter diameter shaft, 390 meters long.
- A 3-meter diameter tunnel, 1,375 meters long.
- Two surface and tunnel access (SATAC) experiments.
- Expansion of surface production and steam generation facilities.
- Underground production facilities.

For B-3:

- One additional SAC experiment.
- Two additional SATAC experiments.
- Expansion of surface production and steam generation facilities.
- Expansion of underground production facilities.

Total costs are projected to be in the order of $675 million (1982 Canadian) and revenues from the sale of bitumen produced during the 11-year pilot life are expected to total $770 million (1982 Canadian). As such, a net revenue of $95 million (1982 Canadian) is anticipated if pilot results meet expectations.

CONCLUSIONS

The pilot required to effectively evaluate the technical, economic, and environmental feasibility of utilizing horizontal well systems drilled from surface or underground tunnels is a major undertaking. Long periods of testing time inherent in in-situ experimentation, combined with expensive facilities and extension of many interdependent technologies, adds to the complexity of the task. The pilot design attempts to phase technology development and financial risk that will provide conclusive results in a cost effective and timely manner.

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(39)

BITUMEN DEPOSITS OF THE USSR AND THE WAYS OF THEIR DEVELOPMENT.

The bituminous rock accumulations of the USSR occur under various geological conditions (on ancient and young platforms, foredeeps and fold belts) and are characterized by various modes of occurrence, composition, depths and degree of concentration.

The term "bitumen" applied in geologic literature is very vague and broad sweeping. Usually this term implies wide spectrum of naphthedes from high viscosity oxidized oils and malthas to kerites and anthraxolites. The most useful of them from practical point of view, are initial products of hypergenetic alterations of oils: high viscosity oils, malthas and asphalts, which form bitumen accumulations in various type traps, in porous, fractured, cavernous and other reservoir rocks.

There are several classifications of bitumen deposits. The classification of N.S.Shatskiy takes into account the type of bitumen and nature of its occurrence, factors of generation and habitat of bitumen deposits. The classification of R.M.Gismatullin et al takes into consideration structural, geomorphological and hydrodynamic factors of formation and retention of bitumen accumulations, specifically the position of the deposit versus local base level; possible types of bitumens and methods of their development are also considered. It is proposed to distinguish three types of bitumen deposits: 1) structural-blanket, including anticlinal, monoclinal and synclinal deposits; 2) erosional topographic deposits embracing accumulations of erosional remnants, karst depressions, erosional channels and 3) fault related (of local and regional faults) deposits.

The classification proposed recommends to take into account the type shape of accumulation, nature of bitumen and bitumen bearring rocks and magnitude of reserves. Out of the four types of accumulations (blanket, lenticular-blanket, vein and surficial) of major interest are the first two. The blanket type deposits contain [illegible] of million-billion tonnes of bitumen-in-place and the len-

The blanket and lenticular-blanket bitumen accumulations can be subdivided according to the structural shape of bitumen bearing layers and nature of bitumen saturation.

Surficial deposits of natural bitumens(kir accumulations, asphalt lakes) occur in areas of oil seepages and in fault zones. Almost all accumulations of this type are of moderate extent and reserves.

Bitumen deposits are known to be closely associated with oil and gas accumulations and because of that the present notions and principles of subdivisions of petroliferous territories should be changed.

R.H.Valeev's and I.S.Goldberg's suggestions provide for definition of a bitumen-petroliferous basin as the main unit of regional subdivision. A bitumen-petroliferous basin is a large downwarped area which ensures hydrocarbon generation,migration, accumulation and retention of oil,gas and natural bitumen accumulations. Petroliferous and bitumen-petroliferous basins constitute a continuous line of evolution including transient forms. The bitumen-petroliferous basins are characterized by extensive hypergenetic processes resulting in oil accumulations turning into bitumen ones. Within bitumen-petroliferous basins, very much like within entirely petroliferous basins, areas, districts and zones of oil,gas and bitumen accumulation may be defined.

The subdivision of bitumen-petroliferous territories for the country as a whole needs additional substantiation.

Within the Volga-Urals bitumen-petroliferous basin the South-Tatar - Melekess and South-Emba bitumen-petroliferous areas and also the Zhiguli and Malo-Kinel bitumen-petroliferous districts may be defined; within the Lena-Viluy bitumen-petroliferous province- the Anabar and Olenek areas and Turkhansk, Siligir-Markhin, Tuelbinsk and Ayan-Maysk bitumen districts are being recognized; within the South-Mangyshlak area -the Taspas-Tubedgiksk district is defined; within the South-Caspian basin - the Apsheron, West-Turkmen, Kakhet and other districts are recognized. Also bitumen-petroliferous districts are detected within the Timan-Pechora,Pre-Urals, Pre-Caucasus and Dnieper-Donets basins.

The review of national and international geological data

The formation and magnitude of bitumen deposits is mostly controlled by the genetic type of the bitumen-petroliferous basin. Areas of maximum bitumen concentration are reported in the bitumen-petroliferous basins of ancient platforms, where all major bitumen deposits tectonically are confined to the uppermost parts of regional monoclines,to the flanks of the anteclises and the rims of large depressions filled with thick sedimentary sequences. For example, in the Volga-Urals basin these are confined to the rims of the Melekess depression and to the slopes of the Tatar arch; in the East-Siberia - to the flanks of the Anabar anteclise. The reported accumulations are mainly of blanket and lenticular-blanket type, vein and kir deposits being very uncommon.

The basins of young platforms do not contain major bitumen deposits. In a few locales individual accumulations of high viscosity oils and kir accumulations have been reported. They are confined to faulted structures.

In the foredeep and intermontane basins the bitumen deposits are usually not numerous and are as a rule, represented by asphaltites, kerites and sometimes by vein and blanket type ozokerites; small-sized deposits of malthas and asphalts associated with faulted and eroded folds are also documented. Within geosynclinal basins bitumen deposits are less common and are mostly represented by asphalt lakes,kir accumulations etc. All the major bitumen accumulations are associated with bituminous terrigenous sediments,deposited under near-shore, deltaic environments, or with carbonates altered by post-sedimentation processes. For example, in the Tatar Republic,USSR one of the major bituminous complexes - the Sheshmin horizon of Ufimian stage is of bar origin. Hence it varies widely in thickness and reservoir properties. The thickness reaches 25-40 m, porosity - 35% and permeability - several darcies. The high grade Permian carbonate bituminous rocks in the Tatar Republic, USSR owe their high quality to the high secondary porosity, fracturing and abundance of cavities.

The degree of bitumen saturation, type and bitumen concentration are also largely controlled by the age of the bitumen bearing sequences. All the major world bitumen deposits are known to are associated with Mesozoic and Tertiary rocks; in more ancient sediments, bitumen concentrations are usually much lower as a result of intensive and prolonged hypergenetic processes and are represented by malthas, asphalts and asphaltites (for instance,Olenek Siligir-Markinsk and other deposits).

In many areas the bitumen bearing sequences occur in lower parts of the transgressive series,which overlie the paleorelief. In this case the regional hiatus at the bottom of the bitumen bearing sequence used to act as avenues for hydrocarbon migration out of large areas of petroleum origin.

The distribution of the bitumen deposits was undoubtedly greatly affected by the hydrodynamic environment. Almost all the known bitumen deposits occur in the zones of active infiltration by fresh and low salinity waters. The formation and retention of the bitumen deposits results from the processes of hydrocarbon oxidation by sulphates,bacteria and oxygen contained in infiltration waters. Besides the screening effect of the formation waters flow resulted in the hydrodynamic barrier which protected the bitumen deposits from complete break up. Due to the rapid oxidation the oil lost its mobility and in spite of the lack of prominent structural and stratigraphic traps it formed self-sealed deposits (for instance, the Olenek deposit).

The problem of investigation of bitumen resources in our country was first dealt with the Tatar Republic. The first information on the wide occurrence of bituminous rocks in the Tatar Republic date back to the XVIII century.Since then repeated investigations have been carried out to assess commercial viability of the deposits.The detailed investigation of the bitumens was revived only 2-3 decades ago. Since 1970 onward bitumen oriented drilling work has been carried out in the Tatar Republic. Besides, the bituminous rocksare assessed concurrently with drilling of numerous structural wells by coring additional intervals and conducting special geophysical investigations. In a number of other bitumen prospective areas research efforts have been initiated based on the [illegible]view of geologycal, geophisical and drilling information available. In the Tatar Republic these efforts have resulted in the discovery of about 70 bitumen deposits including 20 deposits being under various phases of appraisal. Five bitumen bearing horizons are defined in the Permian rocks of the Tatar Republic (Asselian, Sakmarian, Ufimian, Lower Kazanian and Upper Kazanian). The first two horizons are composed of carbonate rocks with porous-cavernous and fractured reservoir rock types. In the Ufimian stage, the Sheshminsk sandstone is productive. It has high pore volume type of reservoir. In the Kazanian stage, the reservoirs are represented by the carbonate-terrigenous rocks with porous and cavernous-fractured type of reservoir The reservoir properties and thicknesses of bituminous members and layers vary greatly: in terrigenous rocks porosity is from 3-5% to 40-45%, permeability - from a few units to 1000-1200 md, thickness-from 1 m to 40 m; in carbonate rocks porosity ranges from a few percent to 20-35%, permeability - from 0 to 500 mdarcy, thickness - from a few meters to 20 m.

The bitumen deposits of the Tatar Republic are mostly associated with local structures. And in the Upper Kazanian sediments they are associated with swells and large terrace-like zones. Most of the known bitumen deposits are of lenticular-blanket type. According to the nature of the reservoir there are single and multiple reservoir deposits. Many deposits are underlain by water.

All in all, more than 200 bitumen pools and prospective bitumen areas may be tentatively identified to date. Most of them are in the Sakmarian and Ufimian sedimentary complexes.

The formation of the bitumen deposits in the Permian sediments of the Melekess depression and the South-Tatar arch is thought to be related both to the processes of lateral step-by-step migration of oil from the south-east areas of the Russian platform, and to the processes of vertical migration from the underlying Carboniferrous and Devonian sediments.

Most of geologists in the USSR reject the idea of the generation of initial oil in the Permian sediments of the Tatar Republic primarily because of the unfavourable geological-geochemical sedimentary environments of Permian rocks.

The highly cavernous and permeable carbonates of the Sakmarian stage, which had been repeatedly subjected to erosional processes, may have served as the main complex for lateral migration. The ideas have been expressed on multi stage introduction of oil into the Permian reservoir rocks.

That is why despite the effect of hypergenetic processes the pore space is completely filled with heavy oil residues. The lack of regional continuous Kungurian salt seal and the presence of major faults facilitated vertical migration of hydrocarbons.

The occurrence of the bitumen deposits within the bitumen bearing area is controlled by the distribution of favourable structural traps, reservoir rock sequences, shale interlayers and by the nature of hypergenetic processes. Of special importance for the occurrence of bitumen deposits within the Permian sequences are shale interlayers and members, which distribution controlls the position of the main bituminous sequences in the Permian succession and the nature of bitumen deposits.

The hypergenetic processes breaking up the oil pools of the Permian sediments in the Tatar-Republic took place during the entire Mesozoic and Cenozoic. The tectonic upheavals resulted in the termination of hydrogeological isolation of the Permian sediments and in initiation of intensive processes in the existed oil fields (oxidation, degasation, increasing of specific gravity etc.) Some pools were cut by erosional channels during the Neogen. Degree of hypergenesis controlls the bitumen type in the deposits. In most destroyed deposits the bitumen is represented by asphalts and in less destroyed - malthas or malthas-heavy oils.

The specific feature of many bitumen deposits is the lack of distinct bitumen-water interfaces within traps,the occurrence within the deposits of intervals of various degree of bitumen saturation, the presence of flushed zones and fractures and water-bearing interlayers of various solinity and hydrogen sulphide content. All this testifies the complex nature of bitumen accumulations. A number of bitumen deposits are reported to have ancient oil-water contacts of previously existing oil pools,which are recognized by the extensive epigenetic carbonatization of sandstones,interbedding of bitumen saturated and unsaturated rocks.The aerial extent of many bitumen deposits disagree with the structure of the bituminous layers.

Exploration of the bitumen deposits in the Permian sediments is carried out employing structural maps,since local closures usually correspond to the maximum thicknesses of bituminous rocks (the

Sheshminsk formation and others). While appraising the discovered deposits the triangle well pattern is usually used with well spacing from 500 m to 700-1000 m. Drilling density during the first stage of appraisal operations is 0,3-0,8 km^2 per well.

A few words about the properties of the Permian bitumen in the Tatar Republic. Their specific gravity ranges from 0,95 to 1,15 /cm^3, viscosity-from hundreds to many thou-sands of centipoize. The elementary composition of the Permian bitumen is the following: carbon - 80-84%, hydrogen - 10-12%, sulfur - 3,5-8%, nitrogen and oxygen - 0,2-9,7%. The group composition: asphalts - 5-35%, resins-12-60%, oils - 20-70%; paraffin content does not exceed 1%. In terms of stock properties the bitumens can serve as row material for motor fuel, low temperature lubricants and also all grades of bitumens for road building and general construction.

Of major importance for bitumen exploration are the Zhiguli, Malokinel and Belsk bitumen-petroliferous areas, where local bitumen deposits, including the vein type (for instance, Sadkinsk, Ivanovsk, Velikhovsk etc.), have long been known.

Numerous (more than 50) surficial type bitumen deposits are reported in the Emba bitumen-petroliferous area. They are associated with salt domes. In a number of appraised deposits bitumen content reaches 15-20%.

In the Taspas-Tubedgik bitumen district of the Mangyshlak area the Yura-Lower-Cretaceous high-grade bitumen accumulations outcrop: the Taspas, Tubedgik deposits, the Dgangurlin locale with unassessed resources. Attempts have been made to employ these bitumen deposits in road building and industrial construction.

Of unquestionable potentialities is the Timan-Pechora bitumen-petroliferous basin, where major bitumen accumulations (from high viscosity oils to asphalts) are known in a number of locales (Yarega, Usa, Izhma etc.). Surficial bitumen accumulations of a wide stratigraphic range from Silurian to Upper Permian are documented on many eroded structures (the Chernov, Chernyshov ranges, the South-East Timan).

Of great bitumen potential are the East Siberia areas. The Olenek bitumen deposit is well known. It is associated with the South-East slope of the Olenek arch. The bituminous Permian sandstones transgressively overlie Lower-Middle Cambrian sediments.

The bitumen saturated sandstone members are from 5 to 50 m thick and have porosity from 1 to 20% and more and permeability up to 100 md. They extend over the distance of 50-60 km. Besides, individual bituminous sandstone lenses of 1-1,5 km in length are reported.

The en echelon belt-like extending zones of intensive bitumen saturation are confined to small structural terraces, which complicate the structure of the gentle monocline dipping in the Lena-Anabar foredeep.

On the South-East slope of the Anabar shield the Siligir-Markhinsk deposit is confined to the Markhinsk swell. Here bitumen saturation is associated with Lower and Middle Camdrian limestones and dolomites. The swell is asymmetric and faulted and has trap sills. According to K.K.Makarov, bitumen saturated strata form a wide (several tens of kilometers) belt up to 6 thousand sq.km in areal extent. The bitumen saturation is controlled by the pattern of lithological variations within limestones and dolomites. Maximum bitumen saturation is recorded in carbonate reservoir rocks with secondary intergnalura porosity in the most uplifted parts of the Markhinsk swell. The thickness of the bitumen saturated layers is up to 15 m. They interbed with low grade bituminous strata. Gross thickness of the bituminous sequence is 500 m.

On the North-West slope of the Anabar shield in Lower Cambrian sediments bitumen deposits are documented in the Rassokhinsk area. Here the layers of low grade bituminous sandstones interbed with the strata almost entirely deprived of bitumen.

It should be noted that scientifically substantiated assessment of bitumen resources have not been carried out in our country as yet. However it is noted that the majority of bitumen resources will be confined to the bitumen-petroliferous provinces of ancient platforms (Volga-Urals, Lena-Vilyuy, Timan-Pechora). The bitumen-petroliferous regions and districts of young platforms, foredeeps and intermontane basins have much lower potential. Most tumen resources are associated with Paleozoic and basically Permian sediments. Sizable resources are confined to the carbonate bitumen complexes, especially in the Volga-Urals, Lena-Vilyuy and Timan-Pechora provinces. Type of bitumen is an important feature of practical value of bitumen resources. In the aggregate potential resources malthas will predominate. However ratio of various types for major provinces is supposed diverse. Thus, for example in the Volga-Urals province malthas will predominate, but in Lena-Vilyuy and Timan-Pechora provinces-asphalts and asphaltites (up to 60-90%).

The most important task of the near future is to work out scientific foundations for assessment of bitumen potential.

In the USSR investigations on the development of bitumen deposits are conducted in three directions: surface and underground mining; mine drainage; in-situ well development.

First attempts for the development of bitumen and high viscosity oil deposits employing mines were made several decades ago in the Daghestan ASSR, Azerbaijan SSR, Groznyy, Ukraine etc. However, for diverse reasons the operations in these areas did not advance beyond test efforts. The Yarega is the only deposit where commercial underground mining is used. The specific gravity of the Devonian bitumen oil is 0,961 g/cm^3, viscosity - 15200 cp; depth - 180 - 200m reservoir rock porosity - 24%, permeability - 3,5 darcy. The inclined-well system of thermal-mine development have been efficiently employed here of late. According to this system production units are cut in the pay proper, and the wells, in which heat-carrier is injected, are drilled within the pay. Expected recovery ratio, when employing this system is 30-35%. But the previously used system which provided for mining 20-30m above the pay formation and drilling numerous vertical and steep wells from these mines, ensured the recovery ratio of only 3,5%.

Open-pit mining and drifting of bitumen deposits was carried out on individual accumulations of the Tatar Republic and Kuybyshev area.

Most prospective in the development of bitumen and high-viscosity oil fields are in-situ well methods. Using these methods bitumen is produced by wells after heating the reservoir by steam injection, partial burning etc. These operations are under way on a number of locales in Krasnodar region, Emba, Sakhalin, Azerbaijan

Of particular interest is employment of various methods for the development of bitumen deposits in the Tatar Republic. Here research operations are under way on screening the most effective methods of bitumen production from Permian clastics and carbonates. All possible methods both in-situ well and surface and underground mine technique are tested. Great amount of laboratory research on steam, water, solvent displacement and on in-situ combustion etc. have been conducted.

Pilot production operations have been already initiated or are planned on a number of bitumen deposits to work out methods of bitumen production. Thus, for instance, in-situ combustion have been applied in three locales, huff-and-puff and steam injection - -in two locales; in some fields shafts, drifts and open-pit mining is planned. Tentative experimental data unequivocally indicates commercial viability of these methods for the development of bitumen deposits in the Tatar Republic. The thermal methods are established to be efficient only for relatively mobile bitumens residing mostly in sandstones with high pore space and permeability; in carbonates and shaly-arenaceous rocks thermal methods as a rule are low efficient. In developing immobile bitumens only mining methods may be efficient providing for subsequent surface extraction of bitumen from the mined rocks. When using the extraction method bitumen recovery ratio can reach 80-90%. The lithological-physical properties and the degree of bitumen saturation also control the conditions of bitumens development to a great extent. In flows of water-free or low water-cut bitumen are usually obtained from the reservoir rocks with bitumen saturation 80-90%. At lower bitumen saturation and higher viscosities the water-cut of the produce steeply increases and amounts to 90% and more. The latter can be accounted for the presence within the bitumen deposits of water bearing interlayers or fractures connected with edge water zones.

Of major importance for the development of bitumem resources is elaboration of the classification for bitumen deposits and reserves on the basis of geological and technical information on bitumen accumulations. The classification should first of all take into account practical value of bitumen deposits, that is amount of reserves, mining conditions (type and depth of deposits) nature of bitumen saturated rocks, thickness, degree of saturation, type of bitumen, hydrogeological conditions etc.).

Presently some areas are prepared for detailed bitumen exploration. These are, in the first place, the bitumen areas of the Tatar Republic, Emba and Azerbaijan, where tangible amount of specially allocated drilling should be carried out. In other areas reconnaissance surveys and wildcatting should be performed in the first place.

The development of bitumen deposits in these areas may be prospective for the production of both hydrocarbon feedstock and various bitumens (for road building and general construction). Of major interest is integrated utilization of bitumen deposits, when bituminous rocks are used as building materials. The efficiency of bitumen development can be increased by concurrent extraction of trace elements.

However,presently,despite the major bitumen potential of the Soviet Union, only prerequisites for bitumen utilization for road building have mainly been created.

Research in bitumen resources of the entire territory of the USSR are planned to be expanded. Priority areas should be defined and their practical value and possible application of the production methods and bitumen utilization should be assessed.

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1982 ANNUAL HEAVY OIL/EOR CONTRACTOR REPORTS—PROCEEDINGS

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THE HEAVY OIL PROCESS (HOP)

By

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ABSTRACT

Anticipating the need for vastly improved methods of recovering heavy oil, Barber Oil Corporation embarked upon the development of the Heavy Oil Process (HOP) in 1976, and in 1978 formed The HOP Corporation (HOPCO). (Since that time HOPCO has become affiliated with Cornell Oil Company). The main feature of HOP is the placement of steam adjacent to a vastly greater volume of oil-bearing formation than is possible by any other thermal recovery method.

HOP is a significant departure from conventional thermal processes for recovering heavy oil. Simply, HOP recovers more oil in place faster and uses less steam to accomplish it. It is anticipated that HOP may be employed in reservoirs which do not respond economically to conventional thermal processes. The reduction in steam consumed per barrel of heavy oil produced also has environmental advantages, as does the overall HOP design, which contains within the process system hydrocarbon vapors produced from the reservoir.

The HOP concept involves placing the heavy oil reservoir initially on a "hot plate," whereby steam is injected at the bottom of the oil-bearing formation from horizontal wells radiating from a central point like spokes on a wheel. A HOP unit consists of three major components:

1. A large diameter vertical borehole terminating in a below-ground cavern at the base of the oil strata. Intermediate level caverns may be considered for multiple sands or in very thick sands.
2. Horizontal wells or laterals extending radially from the cavern into the oil sands to serve as steam injectors and heavy oil/water production lines.
3. Conventional above-ground facilities including steam generation, crude oil recovery and water treatment equipment.

The optimum operating conditions for each HOP complex are being determined by mathematical simulation followed by testing of a demonstration unit in a specific reservoir. Variations in steam injection rates and the total amount of steam injected per cycle are being evaluated on a lateral by lateral sequence to determine the effect upon both heat absorption and steam dissemination in the reservoir. One mode of operation that looks promising based on

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Copies of this paper are available from the author.

computer simulation is to inject steam consecutively into each set of adjacent laterals until a predetermined quantity has been delivered into the reservoir. Each lateral pair will be consecutively placed in a soak phase and then in an oil/water production phase. Steam injection cycles will be either lengthened or repeated sequentially from lateral to lateral until the optimum oil recovery is attained. The oil-water mixture entering each lateral will be lifted to the surface by means of an individual pump for each lateral. It is planned to evaluate the use of conventional vertical injection in conjunction with the lateral producers.

The first commercial demonstration of the HOP technology is at a site in the Kern River Field near Bakersfield, California. Construction has been completed and operations have begun.

Cornell hopes to expand the Kern River project as soon as possible and plans to set up demonstration operations in other major heavy oil areas of the United States, Canada, and Venezuela. The company has applied for a number of patents covering HOP, both in the United States and abroad, and was granted several, the first of them in July 1979.

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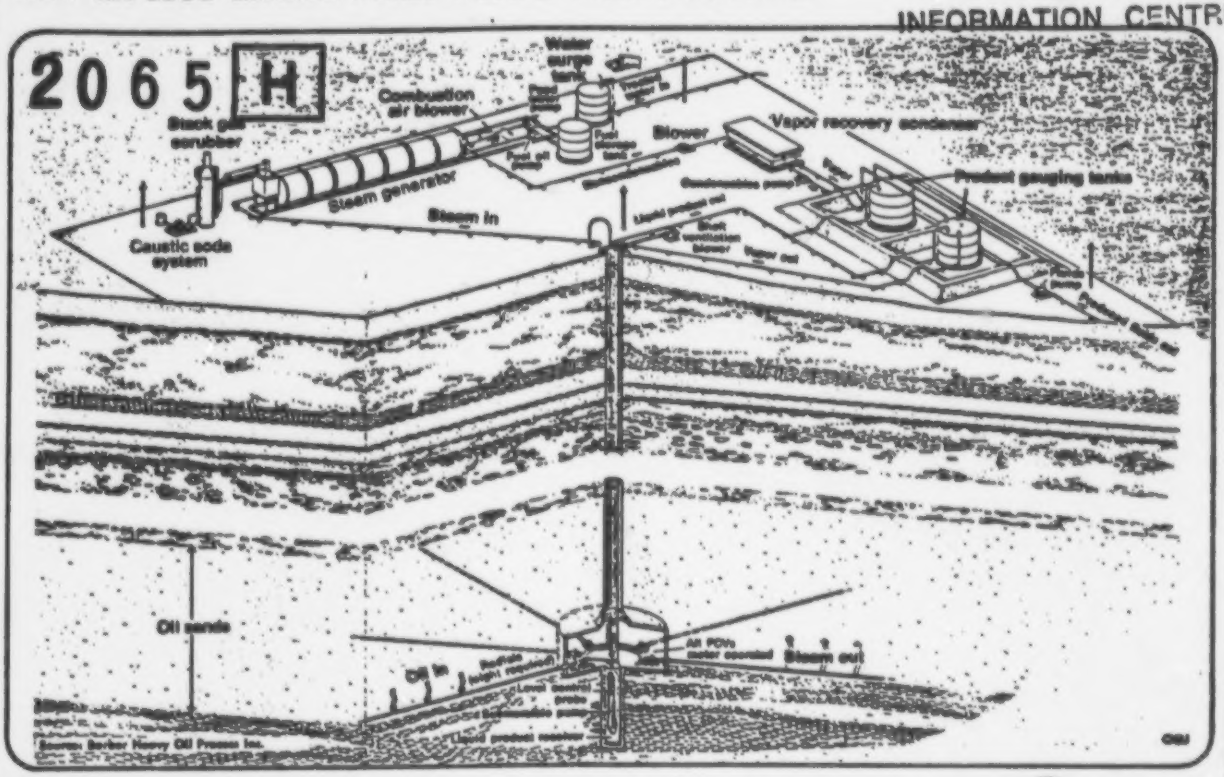
How the HOP method would work in Kern River field



Source: Barber Heavy Oil Process Inc.

Field work begins on unique heavy oil process

DEVELOPERS last week began field work on a new method designed to produce heavy oil by injecting steam through tunnels drilled horizontally at the base of the reservoir.

The unique approach has indicated 65% recovery of oil in place during laboratory tests. Conventional steaming through vertical holes recovers about 50% of oil in place.

Barber Heavy Oil Process Inc., a subsidiary of Barber Oil Corp., New York, is using the patented process on a 25-acre farmout in California's Kern River field.

The theory behind the method, known as HOP (for Heavy Oil Process), is that by steaming through horizontal lines, the operator increases ten-fold the exposure of the steam to the sand.

A company spokesman explained, "We will have 5,200 ft of horizontal injection lines for the 25 acres. If you drilled 10 vertical holes, you would have only 500 ft of injection pipe in the formation."

How it's done. Barber last week began drilling an 84-in.-diameter hole which will reach a depth of 700 ft.

After casing with 60-in. pipe, workmen will construct a concrete cavern 25 ft in diameter and 20 ft high.

From the cavern eight lateral holes with 8⅝-in. tubing will be drilled horizontally for distances of 400-700 ft to cover the rectangular shaped 25-acre area to be produced.

Steam will be driven into the formation through perforations in the laterals.

Steaming will be halted after a time, and oil and water will flow through the laterals and move to the surface.

"We don't yet know the length of the cycle," Barber said. It depends on how much you can inject before it stops being receptive. We might steam 2 months and produce 6-8 months."

Barber will have surface facilities to generate steam. The system will permit injection into pairs of opposite lines in sequence, sweeping around the oil sand on a rotating basis.

The effect of underground lateral steaming is the creation of what Barber calls a "hot plate" beneath the reservoir.

"Like current production methods using vertical wells, heat and residual steam pressure will induce the highly viscous oil to separate from the sand and flow into the pipe," Barber said.

"But unlike other methods, HOP takes advantage of the tendency of steam to rise through the formation and for gravity to carry the flowing oil downward."

Barber hopes to recover about 1.6 million bbl of oil, or 68%, during a project life of 7 years.

Cost is estimated at $6-7 million when construction is completed and facilities installed by early 1981.

Barber can recoup 75% of its costs through the Department of Energy's tertiary enhanced recovery incentive program.

The risks. Because the project is the first tried in the field, Barber recognizes certain risks involved.

While horizontal drilling has been conducted in coal seams and other substantial strata, it has never been done in unconsolidated, oil-bearing sands.

What's more, uniform, controllable steam distribution into the oil sands is essential to achieve predicted recoveries. Channeling of steam from

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laterals or loss of steam from the unconfined drill site could reduce recovery and therby mar the economics of the project.

Barber also recognizes the need for controlled, efficient removal of the hot oil/water mixture from the reservoir following the injection and soak cycle.

Other areas. Barber hopes to expand the demonstration project soon—not only in Kern River field but in other heavy oil areas of California and the U.S.

The company is prepared to license its method to others but is more interested in direct participation.

Of particular interest are Coalinga and Paris Valley fields in California, Caddo Pine Island field in Louisiana, and certain fields in Wyoming, Canada, and Venezuela.

Expansion. The current demonstration project, located on a farmout from Shell Oil Co., is the first unit of several which Barber believes would produce at maximum efficency.

The company anticipates that four to 10 units, forming a production complex sharing centrally located aboveground facilities, would be possible in expanded operations.

The initial project in Kern River contains the following characteristics:

- Depth of sand: 650-800 ft.
- Net sand thickness: 60 ft.
- Initial reservoir temperature: 90°.
- Reservoir pressure (assumed): 34.7 psi—top of sand: 42.0 psi—base of sand.
- Oil viscosity, 5,050 cps @ 80°; 23 cps @ 250°.
- Gravity: 14°.
- Porosity: 27%.
- Absolute liquid permeability: 2,500 md.
- Original oil in place: 1,275 bbl/acre ft.

"The computer simulation for this demonstration unit has defined multiple cycle sequence of steam injection, steam soak, and heavy oil production phases," the company says. "For this site, a five-cycle sequence would require about 60 months of operational time to recover about 65% of the estimated original oil in place."

Steam injection would average about 3 bbl of water equivalent for each barrel of crude produced.

The laboratory study indicates that, financially, the method should be superior to conventional steam stimulation operations in the Kern River field.

While the Kern River project is drilled to a depth of 700 ft, Barber believes it can extend this to as much as 2,000 ft. Potentially, it could go to 2,500 ft, but 2,000 ft is current maximum under consideration.

WATCHING WASHINGTON

with JOHN H. JENNRICH

Mexico: No longer a neglected senorita

THERE'S been much in the news lately about energy supplies from Mexico. But neighbors aren't necessarily neighborly, a point made by former Texas congressman Robert C. Krueger, now ambassador-at-large and the U.S. coordinator of Mexican affairs.

"In perspective," says Krueger, "Mexico is inclined to feel like a long-neglected senorita who now is being ardently courted. Mexico has to wonder about how heartfelt are the U.S. intentions." And America's intentions are becoming increasingly single-minded.

Well they might. The senorita is looking better all the time, sitting in the light of flared gas that could instead be recovered and sent north. Further, oil reserves have increased during the past 3 years from 10 billion bbl to about 32 billion bbl.

"Mexico, if it chooses, can be a major oil exporter in the next few years," says Krueger. But he emphasizes the "if." He notes that Mexico's energy ministry is known as the Department of Patrimony, indicative of the feeling that oil and gas are a paternal inheritance. "It's difficult to sell one's inheritance," says the ambassador. "And Mexico has no intention of doing so lightly."

Or cheaply.

LAST September, the ambassador helped conclude a deal on gas calling for the U.S. to pay $3.625/Mcf, at that time the highest price in the world for gas delivered overland. He tried for a lower price.

But he tells the story that in late August, when Mexico was asking $3.75 and the U.S. offering $3.50, he was reminded by one of the Mexicans of bargaining over oil in 1938. At that time, he was told, the major U.S. oil companies doing business in Mexico were asked for a 1¢/hr increase in wages for their Mexican workers. The oil companies refused. As a result, Mexico nationalized the oil industry. "Today," says Krueger, "the Mexicans still celebrate National Oil Day."

The moral of the story, he was told, is not to quibble over a penny. Shortly after hearing the story, he says, the U.S. agreed to a price of $3.625/Mcf. And since then, the agreed price has risen to $4.47/Mcf.

Even at $3.625, Krueger predicts, Mexico wouldn't be selling gas as fast as it could be produced. "It wants to grow," he says, "but not at the expense of internal stability."

Krueger believes the U.S. should favor whatever it takes to make a strong, stable Mexico. He quotes English poet John Donne: "No man is an island, entire of itself . . . Therefore, ask not for whom the bell tolls. It tolls for thee."

"The bell tolls for us as well as Mexico," Krueger declares. "Our fates are intertwined."

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Oil Mining in Germany

Dr. F. Hoffmann and Dr. W. Ruehl

Introduction

Though, in the whole world, oil had been recovered by mining from shallow band shafts already in the Middle Ages, and though in the 19th century numerous shafts of a depth of up to 262 ft. (80 m) were operated in the valley of the upper Rhine, it is yet to be considered a pioneering venture when, in 1915, the first systematic planning of oil mining was initiated in Germany, a pioneering venture, because it became the expression of the knowledge that only part of the oil can be produced by normal primary recovery methods, while the rest could, at least in part, be recovered by enlarging the oil-yielding surface.

German oil mining was started as a method of secondary recovery. And yet it is rather doubtful whether it is always applied as such, e.g. at Heide, it was a method of primary recovery, because every other production method had failed. In other cases oil mining will always take the second place, because the reservoir should first be depleted of any pressure or gas, i.e., it should first be made ready for mining.¹ Furthermore, the initial decision to take up mining will frequently be made impossible by insufficient financial or technical means that can only be provided in the course of time. These conditions will vary at different times and in different reservoirs; they are not decisive, however, though it is important, in periods when economic aspects are only considered in the second place, to have a method in hand by which a depletion of practically 100 per cent could be effected. This is the case in the direct mining of the oil sand.

The engineering problems above and below the surface have been solved even under the troublesome conditions encountered in the plastic oil chalk of Heide in Holstein, so that we are perfectly justified to regard them as generally solvable. That considerable progress has been made in the low-temperature carbonization and washing is illustrated by the fact that it is now possible to cold-water-treat the Athabasca sands with their highly viscous tar oil of 50,000 to 1,000,000 cp.

And this is the advantage of oil-mining: Even with our present high standard of primary and secondary recovery methods the way to the last per cent of oil exclusively leads through mining.

Various are the problems of oil-mining and the opinions of its significance. At a first glance it could be thought that, with regard to the great progress the science of petroleum has made in the last decade, especially in the fields of primary and secondary recovery, oil-mining would have had gradually to give up all its hopes. Those who say so, however, have not grasped the essence of the matter. They forget that the unrecoverable percentage of residual oil, especially of all heavy crudes and tar oils in the world, is as yet much greater than the percentage that can be recovered. They overlook the problem of the stripper wells, which is of vital importance in all oil countries of the world and is closely related to the topic of mining.

Of course, the economic aspects of oil-mining are dependent upon the respective reservoir conditions and the applied recovery methods. In Germany as well as in Japan, where oil-mining has followed the German pattern since 1940, these problems have been solved, i.e., oil-mining has been operated profitably for 35 years and has been so safe, technically, that the method may be regarded as having completely been brought under control. And even if the economic limits should be reached—is it not a secure feeling to know a method that could be effective in cases where our normal primary and secondary recovery methods cannot be applied or

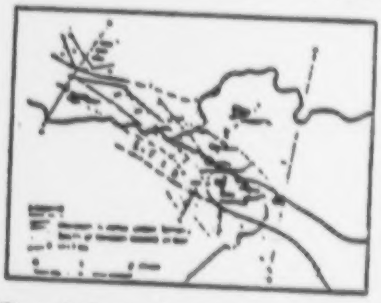


Figure 3—Structural map of top of Wealden in the oil fields of Wietze and Thoeren. (According to H. Weber, 1948.)

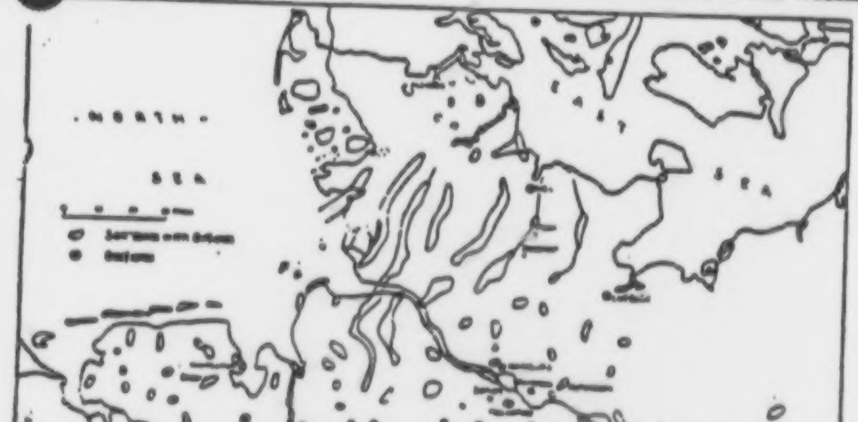


Figure 1—Map of salt domes and oil fields in northwest Germany.

Presented at Meeting of Secondary Recovery and Pressure Maintenance Advisory Committee, Interstate Oil Compact Commission, April 24, 1953, New Orleans, Louisiana.

¹Literature at the end.

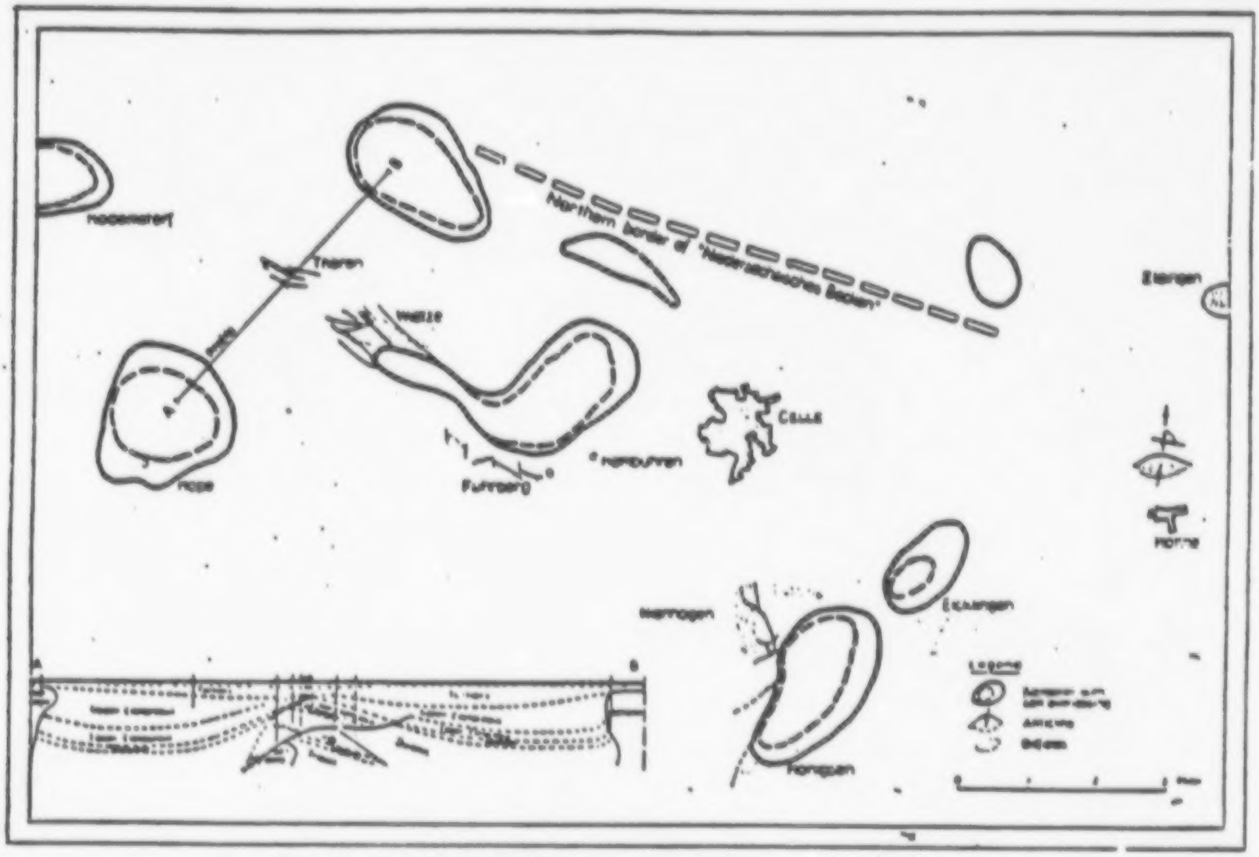


Figure 2—Oil fields on salt domes and deep structures near Celle (Hanover).

will only yield a very small output?

We have refrained from citing the rather comprehensive literature on oil-mining, since it has been our main intention to describe our own experiences at Wietze, Pechelbronn, and Heide. It must not be omitted, however, to point to the earlier report on Wietze by Rice[4] and to the more recent excellent paper on the oil-mining possibilities in the United States by Torrey[5], the general conclusions of which might be agreed to in every respect.

The engineering section of the paper in hand has been written by F. Hoffmann, the section dealing with geology and reservoir engineering by W. Ruehl, the economic section by both.

(A) Geology and Reservoir Technology

(I) Wietze (Kreis Celle) near Hanover

(1) General Geology and Production

(a) Geology

Wietze is located in the northwest corner of one of the approximately 300 northwest-German salt-domes, that extends towards Celle over a distance of 7.2 miles (12 km). Its natural tar seepages have been known since the sixteenth century. After having been exploited by small hand shafts in the following centuries, they became the reason why, in 1858, Professor Hunaeus, by order of the government of the Province of Hanover, drilled the first well into the reservoir, which was completed on May 29, 1859. Systematic exploration was not started before 1874, however, and came to a stop by the middle of the thirties. Up to that time there had been drilled about 2,100 wells in all, of which 1,800 were producers from a depth of about 700 to 1,000 ft. (200 to 330 m). About three hundred are still being produced. The cumulative output of about 80 years is approximately 17 million bbl. of oil (2,800,000 tons), 5 million bbl. (765,000 tons) being due to mining.

The salt-dome is located within the geologically well-known line of the Aller River where, in the meantime, quite a number of other oil fields have been discovered, as well as on the northern edge of the Basin of Lower Saxony which is distinguished by an extraordinarily complete sedimentary series of the whole Mesozoic. The chief reservoir rocks are sands and sandstones in the Rhaetic and Upper Dogger beds as well as in the Wealden and Senonian.

In 1939 the field Fuhrberg-Hambuehren was discovered on the southeastern flank of the salt-dome, and in 1941 the field of Toeren was found in the northwestern extension of the downplugging salt-axis at the greater depths of 1,800 to 4,000 ft. (800 to 1,220 m). Exploratory operations in the northeastern flank sections of the salt-dome did not meet with any success (refer Figs. 1 to 3). As may be seen from Fig. 4, the northwestern corner of the salt-dome is characterized by rather interesting tectonic conditions. When this salt-dome was being uplifted, there had prevailed in that area a general overthrust tendency proceeding from the south to the north, which had had the effect of thrusting the southern flank or crest of the Wietze salt-dome over the northern flank along an "overthrust plane," which we call "Gleitflaeche". Owing to the more pronounced uplifting of the salt-dome at Wietze, deeper stages have been covered there by the Tertiary transgression than at Thoeren. At Wietze we, therefore, distinguish between an upper block above the overthrust plane and a lower block below it.[1] [3] Because of the transgressing Senonian east of Wietze, the geological age of the overthrust can only be defined as pre-Senonian.

In the upper block there are oil sands and oil sandstones in the Wealden, the depest part of the Lower Cretaceous, in the Malm, the Upper Dogger, the Middle Rhaetic, and in clefts of the higher Liassic; in the lower block, however, oil is found only in the Rhaetic, and lastly an oil-impregnation is also encountered in the base sands of the transgressing Senonian.

It has not yet been possible to clarify whether the oil immigrated before or after the overthrust. Its immigration however, might be closely related to these tectonic movements.

No oil has as yet been found in the southern flank of Wietze.

The present report chiefly deals with oil-mining, so we shall only have to discuss the geology and reservoir technology of the Wealden, the upper block

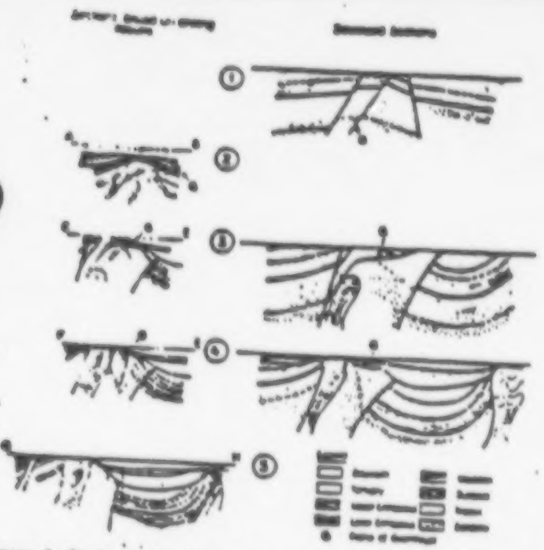


Figure 5—Study of the Tectonic movements of the salt dome between Wietze and Thoeren. (According to H. Weber, 1948.) The stages 1 to 5 represent the development of this structure. While only a flat uplift which is divided into separate blocks may be seen at 1, the second stage already shows the strong movement of the southern flank towards the north and its overthrust over the salt dome, which tilted the brooks into a horizontal position. Thus the overthrust plane of Wietze-Thoeren has been formed. The stages 3 and 4 are especially pronounced in the center of the uplift at Wietze. Stage 5 in the east part of the oil field of Wietze has developed through erosion. Everything has been eroded down to a point below the plane of overthrust.

Figure 6—Tar seepage near Wietze.

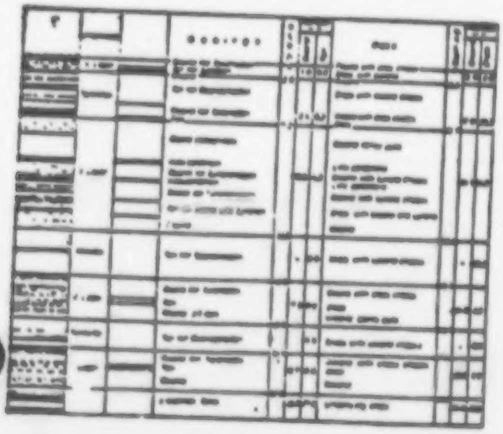


Figure 7—Petrographic standard section of the Wealden deposit at Wietze.

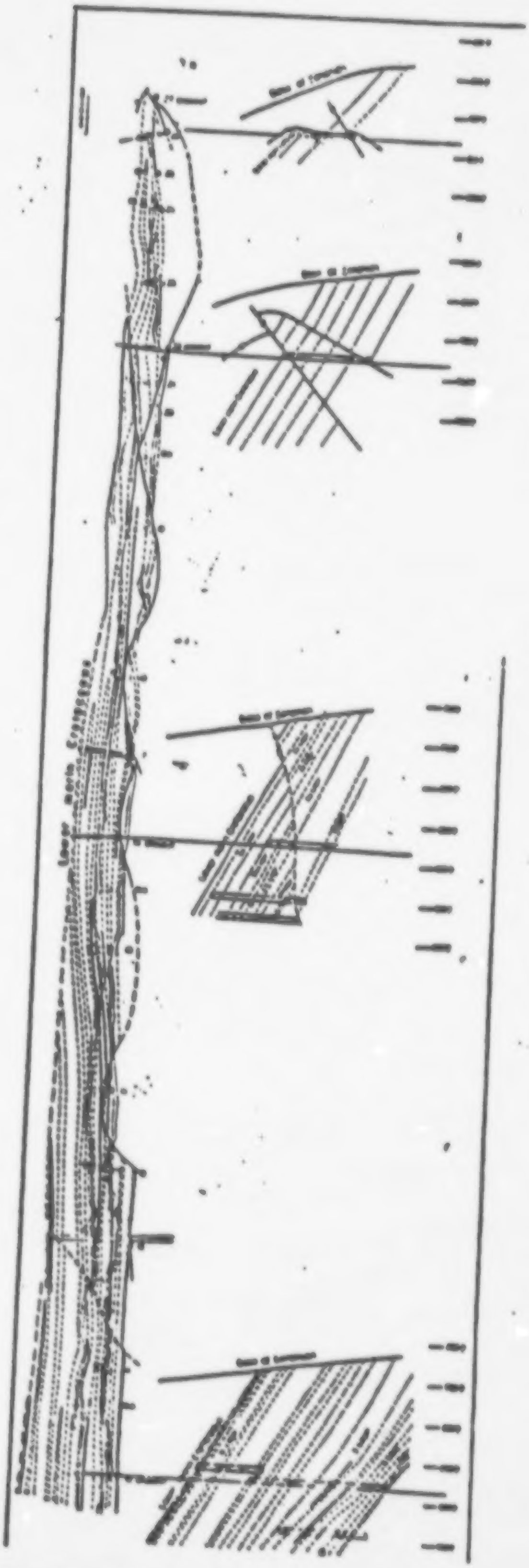


Figure 8—View of the individual deposits in the Schindler Block of Wietze with cross-sections. (According to Kubella.)

at the northwest corner of the salt-dome.

It is quite obvious that by the very considerable process of uplifting strong forces of tension were sure to be called forth resulting in numerous more or less radial dislocations. This is evident from Fig. 3. In between, many other dislocations are also known, as is evident from Fig. 5. While, on the northern flank, the Wealden sands dip rather steeply with an angle of about 55°, they are relatively flat-bedded in the northwestern trend towards Thoeren. Here we observe an angle of dip as low as 10° to 20°. As is evident from Fig. 5, however, oil is mined in all blocks quite independently of these angles of dip noted in the oil sands.

The higher tectonic strain has probably contributed to the formation of the above-mentioned tar seepages, as, in places, the salt-dome, being covered only by diluvial beds, will reach a distance of 230 feet (70 m) from the earth's surface. Fig. 6 shows a tar seepage where the first German oil well had been drilled.

(b) Production

In the course of 80 years a cumulative output of about 12,000,000 bbl. (1,815,000 tons) had been recovered from about 1,800 wells, about 80 per cent being heavy oil from the "upper block" above the plane of overthrust, while 20 per cent were light oil from the Rhaetic of the "lower block". Furthermore, the heavy-oil output recovered up to December 31, 1952, may be broken down as follows:

about 3,395,000 bbl. = 28.4 per cent (512,000 tons) from the Wealden (which is of interest to us owing to the mining)

about 7 per cent from the White Jurassic,

about 31 per cent from the Upper Dogger,

about 22 per cent from the Liassic and Rhaetic,

about 11 per cent from the Senonian.

At present the Wietze mine yields 12,300 bbl. (1,850 tons) a month, while 2,300 bbl. (350 tons) are produced by, in part, extremely old wells.

In the 22 years of its existence the oil mine has yielded a cumulative output of 5 million bbl. (765,000 tons), which are broken down as follows: 3,654,000 bbl. = 72 per cent (551,000 tons) from seepage-oil mining, i.e., from the self-active drainage of seepage tunnels, and 1,306,000 bbl. = 26 per cent (197,000 tons) from oil sand that is excavated and washed. Besides, there are 106,000 bbl. of light oil (16,000 tons), i.e., 2 per cent that have been recovered by horizontal subsurface drilling from the Rhaetic of the lower block.

The seepage-oil recovery of 3,654,00 bbl. (551,000 tons) chiefly consists of th output from the Wealden amounting to 2,800,000 bbl. (543,000 tons) and of the minor Jurassic production amounting to a mere 55,700 bbl. (8,400 tons), that has been abandoned lately.

It is obvious at a first glance that seepage-oil mining has yielded more in 22 years only than about 480 Wealden wells had achieved in 80 years, and that, after the peak production of Wietze, reached in 1908, had long passed, and although the surface area covering the mine is much smaller than the area covered by wells, as may be seen from Table 1.

It should be anticipated, however, that oil mining will effect a much more intensive activation of the seepage covering wide surfaces than the small drainage area opened by a well. This very fact provides the decisive approach to reservoirs producing by gravity.

The figures of Table 1 referring to the mining of the Rhaetic and the Jurassic, are based upon the horizontal holes

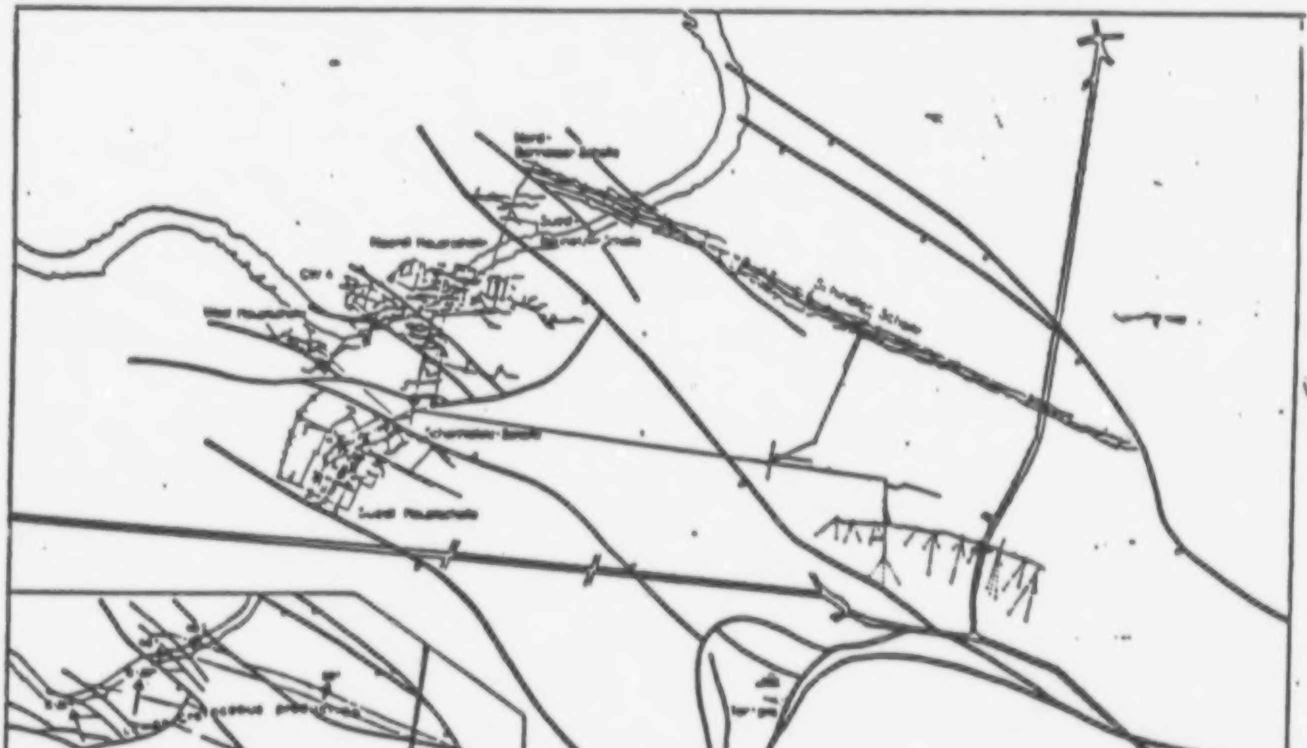


Figure 5—Wealden deposit at Wietze with network of tunnels and arrangements of blocks.

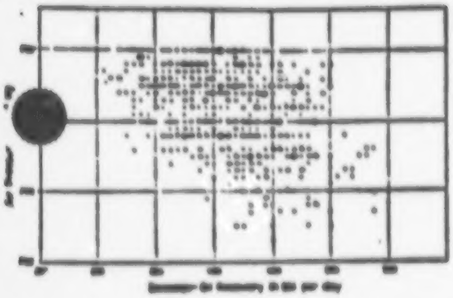


Figure 10 — Effects of atmospheric pressure on seepage-oil recovery from the Wealden. (Daily measurements in 1936 and 1937.)

drilled for light oil into these formations —which, however, will only cursorily be discussed here—as well as on several mining attempts in the Jurassic that have been discontinued.

TABLE 1—Drainage Area in Mining and in Wells

	Mining		Wells	
	No.	Acres	No.	Acres
Senonian	...	...	45	110
Wealden	48	120	107	270
Jurassic	2.4	6	69	170
Rhaetic	10	25	15	40
Total	60	151	236	590

(2) Petrography and Reservoir Technology in the Wealden

(a) Petrography of the Reservoir

The Wealden deposit consists of a s[illegible]ce of loose dry oil sands, sand-[illegible] and limy sandstones totalling 210 [illegible] ft. in thickness (65 to 75 m). In general, it may be divided into four oil sand reservoirs of 100 to 130 ft. (30 to 40 m) combined thickness. We may observe extraordinarily great facial variations, i.e., rather irregular shale intercalations in all reservoirs causing several zones to be absolutely dry. In some places separate layers will unite to a single series of beds, as may easily be observed at the Schindler Block which is steep owing to its location on the north flank. There are generally thin to extremely thin shale intercalations in the sands as well as argillaceous materials in the pores themselves, and shale intercalations in their turn are also most always interbedded with sand layers, so that all contacts between the beds frequently become quite indistinct.

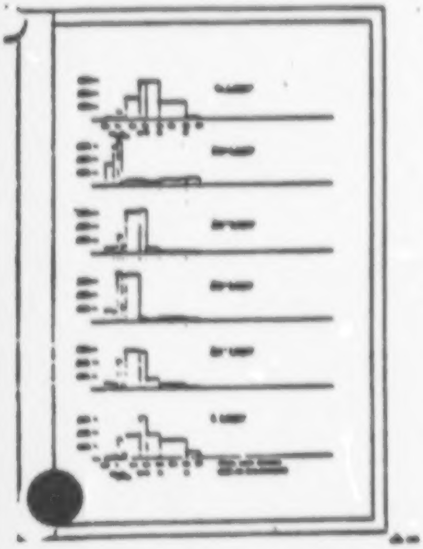


Figure 9—Diagram of petrographic grading of the Wealden deposit at Wietze (west part of Schindler Block) according to grain size analyses. The percentages show the medium width of the individual screen fractions on the basis of about three hundred analyses.

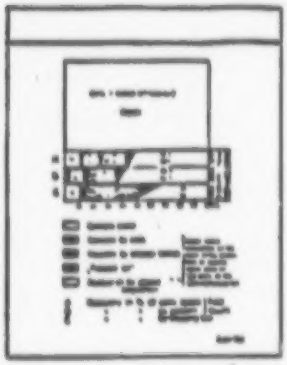


Figure 11—Recovery diagram for 1 m³ (equals 35.3 cu. ft.) of Wealden oil sand at Wietze.

In spite of these difficulties, it is possible to classify the reservoir as shown in Fig. 7. Fig. 8 shows a characteristic view of the separate reservoirs on the steep north flank along with several geological cross-sections.

It should be pointed out that two mining methods are used at Wietze, actual mining by excavation of the oil sand and the seepage of oil from the walls of the tunnels caused by the oil's own gravity. The seepage method is applied to the reservoirs I to III in all blocks, the oil-sand mining by excavation only to the reservoirs III and IV in the blocks where the reservoir has a slight inclination of 10° to 20°. The third reservoir has the greatest thickness, while the fourth and uppermost hardly contains any oil at all.

The sands are fine to medium grained and, as already mentioned, seldom quite pure. In some places both upper reservoirs are a little more fine-grained than the lower, though in general, it is impossible to recognise any characteristic features. Fig. 9 illustrates the petrographic classification.

The porosity of the sands varies between 15 and 42 per cent, the average value of the third and most important reservoir being 36 per cent. As far as the permeability values of such loose sands may at all be determined in the laboratory, they are also extremely variable, ranging between about 1,000 and 20,000 mdy.

As to the rest, the petrographic properties of the sands of Wietze are very similar to the tar-sands of the Athabasca River in northwestern Alberta, which, as part of the McMurray formation, also form a member of the Lower Cretaceous. This not only applies to their vast thickness, which on the Athabasca River even amounts to about 210 ft. (65 m) consisting chiefly of sand, but also to their petrographic composition as regards grain size and shale content. The difference between both reservoirs is mainly in the chemical properties of the crudes, the viscosity of the Athabasca crude being notably higher owing to its proximity to the earth's surface.

(b) Pore Content and Chemistry of Oil and Water

Before dealing with the oil saturations and drainage problems, we shall give a short review of the chemical properties of the oil as well as of the water content. In Table 2 we find a characteristic analysis of the Wietze crude, a typical heavy oil that is frequently encountered not only on German salt domes but also anywhere in the world. It is a typical heavy oil developed as a consequence of the tectonic strain imposed upon the reservoir and having undergone repeated processes of oxidation and polymerisation. The water contained in the voids as well as the constant-level edge-water is a type of brine having the following consistence (refer Table 3).

Since, in the mine, there exist excellent opportunities of taking subsurface samples of the oil sand without any contaminations by drilling mud or water as in wells, we conducted a detailed research programme of the water content several years ago, simultaneously checking the capillary pressure method of determining the irreducible connate water content. Direct measurements of

TABLE 2 — Crude Oil Analyses

	Wietze		Pechelbronn	Heide
	Wealden	Rhaetic	Oligocene	Senonian
Specific Grav.				
(68° F.)	0.944 - 0.960	0.888 - 0.895	0.880 - 0.900	0.945 - 0.980
API.	18.6 - 16.0	28.0 - 26.7	29.3 - 25.7	18.4 - 12.5
Viscosity in cp.				
(68° F.)	1200 - 2300	40 - 60	30 - 180	(2000 - 5000)
(122° F.)	140 - 175	.... -	4 - 25	80 - 250
Asphalt in %	1.36 - 1.85	0.1 - 0.7	3 - 5	2 - 5
Paraffin in %	1.0 - 1.06	2.2 - 3.3	6 - 7	.... - ....
Sulphur in %	1.0 - 1.10	0.6 - 0.7	.... -	1.2 - 2.5
Boiling point				
(°F.)	392 - 428	176 - 320	194 - 257	212 - 392
392° F. in %	.... -	1.0 - 7.0	ca. 8.0	2 - 8
482° F. in %	0.7 - 3.5	8.0 - 15.5	ca. 10.0	3 - 12
572° F. in %	7.2 - 12.5	22.0 - 30.5	22 - 29	15 - 25
662° F. in %	18.0 - 29.0	37.0 - 43.4	.... -	.... - ....

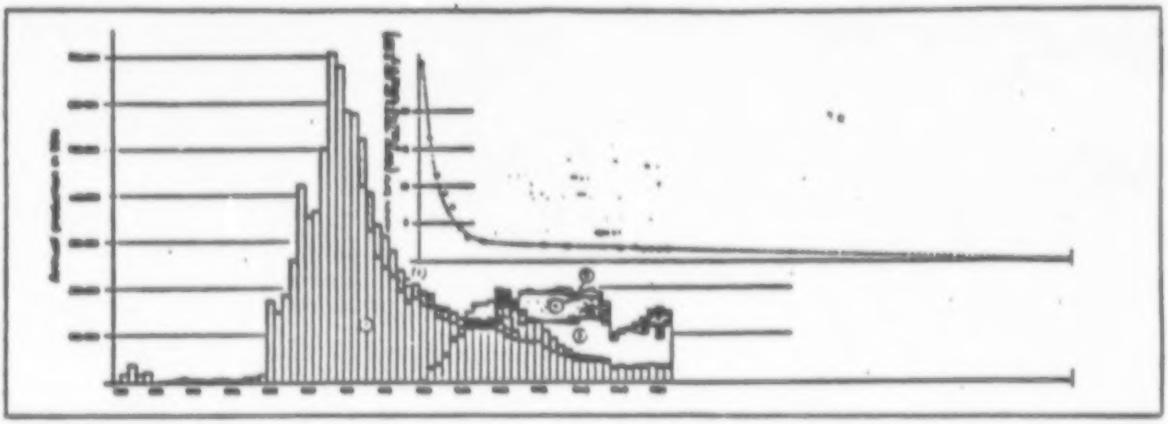


Figure 12—Recovery at Wietze from wells and mine as well as seepage-oil recovery factor per 1 meter of tunnel length from the start of mining.

400 samples yielded a water content of 8 to 14 per cent with an average of 11 per cent. These values have been verified by electric subsurface logging in the mine. In contrast to this, the capillary pressure method yielded values of 17 to 30 per cent. We are perfectly aware that certain reservations have to be made with regard to this research work; without considering the latter, however, the discrepancies between both methods would probably even be greater. Papers covering this subject have been published in American and German oil trade journals.[5 7 8]

(c) Energy

Owing to the above-described complicated tectonic conditions, it is no wonder that the crude is not only heavy—its chemical properties had already been described—but that there could also develop no hydrostatic pressure system on this salt-dome, so that at present there exists no edge-water drive whatever, a condition that is favorable with regard to mining. At Wietze the edge-water level at a depth of 850 to 980 ft. (255 to 300 m) is absolutely constant in the separate blocks. Only in the very beginning had it been possible to detect a weak gas drive during the short flush period, as is evident from Fig. 12. This flush period, however, was soon replaced by pure gravity drainage, which might possibly have been supported by settlings in the reservoir that united with the rock pressure to cause a change of the inward structure of the pore spaces as well as of the surface forces, thereby increasing the oil flow. Similar observations have recently been made in an Austrian oil field by Senolt and Winkler.[9]

An interesting observation should lastly be made that concedes a rather significant effect to atmospheric pressure. Daily measurements made at Wietze in the course of many years showed the oil recovery to be improved at low atmospheric pressures in contrast to high. It is understood that this is no active driving effect, but, on the contrary only an increase of the flowing pressure differential between the reservoir and the tunnel resulting from the natural reduction of atmospheric back-pressure. An example is shown in Fig. 10.

This absence of an active gas or water drive — though disadvantageous with regard to the recovery factor of wells—became the starting-point of oil-mining. In 1920, at the start of oil-mining, there had already been produced by wells 2,240,000 bbl. of crude oil (338,000 tons) from the Wealden. It had been recognised that hardly more than about 15 per cent of the original oil content could probably be produced by normal primary recovery methods. This low ultimate recovery led to a positive attitude towards oil-mining as well as to the birth-hour of secondary recovery in Germany.

(2) Oil Recovery and Drainage in the Wealden

(a) Drainage Conditions and Ultimate Recovery by Wells and Seepage Tunnels

Before dealing with the drainage effects we should once more remind ourselves of two facts.

It goes without saying that the following arguments only apply to the seepage method which yields about 75 per cent of our present total output and chiefly consists of the driving of tunnels. Only 25 per cent are recovered in actual mining by excavating the oil sand and its subsequent washing.

TABLE 3 — Salt Water Analyses

	[illegible]	[illegible]	[illegible]
Spec. Grav. (68° F.)	1.10 - 1.17	1.0 - 1.05	?
Dry Residue (g 1000 cm³)*	115 - 187	20 - 40	1 - 2
Na in %	33 - 37	38 - 42	25 - 26
Ca	0.8 - 2.4	7 - 10	3 - 5
Mg	0.1 - 2.5	1.5 - 2.0	0.5 - 1
Cl'	56 - 62	44 - 48	56 - 58
SO₄''	0 - 3.5	0.5 - 4.0	... ? ...
CO₃''	0 - 0.5	1.3 - 2.0	2 - 4

*To convert to ounces per gallon, multiply by [illegible]

TABLE 4—Wealden Oilsand Drainage by Wells and Seepage Tunnels

1 Total vol. oilsand 564,800,000 cu. ft.
2 Able to yield oil 70% 395,360,000 cu. ft.
3 Oil content 22,585,500 bbl.
Water content 2,802,500 bbl.

(A) On the basis of the effective production
(a) By wells
4 1874-1919: 338,000 to = 2,240,000 bbl.
= 9.9% (of 3)
5 1920-1952: 174,000 to = 1,150,000 bbl.
= 5.1%
6 1953-2000: 15,000 to = 100,000 bbl.
= 0.5%
7 1874-2000: 527,000 to = 3,490,000 bbl.
= 13.5% of p.v.
17.7% of oil content
(b) By seepage tunnel recovery
8 1920-1952: 543,000 to = 3,597,300 bbl.
9 1953-2000: 250,000 to = 1,650,600
10 1920-2000: 793,000 to = 5,248,000
= 23.2% of p.v.
= 26.5% of oil content

(B) On the basis of the oil content in the sand
11 1 cu. ft. oilsand had originally 36% = 0.360 cu. ft. p. vol.
12 Filled with 0.057 bbl. of oil
0.007 bbl. of water
(a) Recovery by wells
13 1920 1 cu. ft. oilsand had 0.049 bbl. of oil
i.e., withdrawn by wells
0.008 bbl. = 15% of oil
= 13% of p. vol.
(b) Recovery by seepage tunnels
In the southern block seepage recovery has ceased, i.e.,
1 cu. ft. oilsand has 0.036 bbl. of oil
i.e., withdrawn by
tunnels 0.013 bbl. = 22.8% of oil
= 19.7% of p. vol.

(C) Summary
Total recovery by wells
15.0 - 17.7% of oil content
By seepage tunnels
22.8 - 26.5% of oil content
Total 37.8 - 44.2%
Residual oil for
oilsand excavation 62.2 - 55.8%

The other aspect is the fact already mentioned that, when oil-mining [illegible] started in 1920, practically all o[illegible] reservoir had already been drilled u[illegible] wells, so that parts of it had quite considerably been depleted in the course of 10 to 40 years. Up to that time about 2,240,000 bbl. (338,000 tons) had already been recovered from the reservoir. For this reason, we should not be surprised to find that, already in 1920, the same as at present, a relatively low percentage of the pore spaces was filled with oil in the upper parts of each separate [illegible]voir, especially of the third, how[illegible] while the oil saturations were [illegible]proved in the lower parts. Above the water level a distinctly "liquid" oil sand is encountered, which is full of oil. If it is desired one may, therefore, divide each reservoir, especially the third, however, into one upper "dry" and one lower "wet" zone.

Furthermore, the seepage ability is also affected by the petrographic properties of the sand. Very fine-grained or clayey sections are in general said to possess a very small ability of seepage or hardly any at all. This especially applies to the fourth and uppermost reservoir. The third reservoir has a seepage ability of about 60 to 65 per cent of its thickness, the second of about 65 to 70 per cent, the first and lowermost of 70 to 75 per cent. Here again, we note that the grains tend to get finer and more argillaceous in the upper part of the Wealden.

Of course, the above-mentioned figures are dependent on the special reservoir properties and exploitation methods; they would be different, if the reservoir temperature—which is 86°F. (+30° C.) at Wietze—were higher and the viscosity of the crude were consequently lower. Thus, the conception of [illegible]eepage ability" may be regarded [illegible] generalised notion equivalent to the "recovery factor" (or ultimate recovery) as related to the thickness of the reservoir.

Table 4, showing the most important drainage figures, will serve to elucidate the following arguments.

The above mentioned Wealden reservoir comprises 564,800,000 cu. ft. (16,-[illegible]00,000 cbm) of oil sand, of which, as already mentioned, about 70 per cent, i.e., about 395,360,000 cu. ft. (11,200,000 cbm) are able to yield oil. If we assume an oil saturation of 100 per cent—though, of course, no laboratory values are available for 1874, the first producing year of this field—and a pore volume of 36 per cent, we obtain total reserves of about 22,585,500 bbl. of oil and 2,803,500 bbl. of water (11 per cent) (3,585,000 cbm of oil and 445,000 cbm of water). We will only make two calculations of the ultimate recovery—one on the basis of the cumulative and estimated future production, the other by determining the oil content of the oil sand samples taken in the mine.

(1) On the Basis of the Output

[illegible]om 1874 to 1920 the whole of Wietze [illegible]roduced about 7,295,000 bbl. of oil [illegible],000 tons), of which about 2,340,000 bbl. (338,000 tons) had been recovered from the Wealden deposit discussed in this report. This makes about 10 per cent of the total reserves of the Wealden of 22,585,500 bbl. (3,585,000 cbm). 1,130,000 bbl. (174,000 cbm) were produced from 1920 to 1952, and further 99,500 bbl. (15,000 tons) will be produced from 1953 to 2000, i.e., to the anticipated end of the production by wells, so that a total of about 3,500,000 bbl. (527,000 tons) may be produced by wells, which is equivalent to a primary recovery of 15.5 per cent of a pore volume or 17.7 per cent of oil content—a value that may be regarded as natural in pressureless sand reservoirs producing by gravity.

In 1920 oil recovery by subsurface seepage took its start in the same area already preliminarily depleted by wells, whereby a tunnel length of 1 ft. will have a drainage area of 26 sq. ft. Even as early as that, it had been recognised that an increase of the surface yielding oil would necessarily lead to an improvement of the ultimate recovery by gravity drainage. About 3,597,300 bbl. (543,000 tons) were produced in this way from 1920 to 1952, while a further amount of 1,650,600 bbl. (250,000 tons) will be added up to the year 2000. From these figures the seepage-oil recovery may be estimated at 5,247,900 bbl. (833,000 cbm) i.e., about 23.2 per cent of the pore volume and about 26.5 per cent of the oil content.

(2) By Determining the Oil Content

The oil content of 1 cu. ft. is a measure which is used as reference in oil-mining, if the miner wishes to estimate the content of the separate districts of his mine. It is obvious that at a porosity of 36 per cent 1 cu. ft. of oil sand will have a pore volume of 0.360 cu. ft., which are filled with 0.057 bbl. of oil and 0.007 bbl. of water (0.320 cbm of oil and 0.040 cbm of water per cbm). When oil-mining was started in 1920, only 0.048 bbl. were obtained in one cu. ft. of oil sand (0.270 cbm per cbm), i.e., 0.009 bbl. (0.050 cbm per cbm) or 15 per cent of the original content had been withdrawn by primary recovery methods by means of wells. This value of 15 per cent correlates relatively well with the value found by the other method.

In the so-called southern block south of the shaft the seepage has, in part, ceased, as the reservoir hardly yields any more seepage oil. Direct mining by excavation of the oil sand was started there. This sand only contains 0.036 bbl. of oil per cu. ft. (0.200 cbm per cbm), i.e., 0.013 bbl. (0.050 cbm per cbm) or 22.8 per cent of the original oil content had been recovered by the seepage method. This value is in relatively good accordance with the value of 26.5 per cent found on the basis of the production trend.

Referring to Fig. 11 we will once more summarize that during the economic life of the field 16 to 18 per cent of the original oil content may be produced by primary recovery methods, and 22 to 26 per cent by seepage tunnels, which makes a total of 38 to 44 per cent. The main content of about 60 per cent will remain unrecoverable by any methods hitherto used. Here we must, therefore, resort to the excavation of the oil sand and to its subsequent washing, which, provided that there arise no economic impediments, will yield practically all of the oil.

We will now discuss the seepage recovery and seepage capacity, because it is a characteristic feature of the method and makes possible a calculation of the reserves. The present seepage-oil reserves—in our case, as already mentioned, 1,650,600 bbl. (250,000 tons)—as well as their future development may be predicted only when making certain reservations, as an eventual declining tendency of the seepage-oil output that may have arisen in the 32 years of seepage-oil production, might be obscured by the fact that new seepage tunnels are driven every year. Early in this year we had just reached the limits of the field, so that only a few supplementary tunnels will be driven in years to come. The tunnel footage in the oil sand was 188,900 (57,600 m) up to the end of 1952, 82,000 ft. (25,000 m) being yet produced and yielding the annual output of 119,400 bbl. (18,000 tons). From both figures an annual seepage-oil recovery factor of

$$\frac{119{,}400 \text{ bbl.}}{82{,}000 \text{ ft.}} = 1.4 \text{ bbl. per ft.}$$

or

$$\frac{18{,}000 \text{ tons}}{25{,}000 \text{ m}} = 0.72 \text{ tons per meter per}$$

yr. has been obtained.

The curve of development of this factor, commencing in 1920, is similar in character to the normal oil-well production curve. (Refer Fig. 12). We calculate the yet obtainable amount of seepage oil by extrapolating this curve; these calculations should be based on the assumption, however, that, during the life of the seepage-oil recovery, uniform sections of the tunnels are abandoned every year.

This curve, however, also indicates in all distinctness that even in this heavy-oil reservoir from which already 2,340,000 bbl. (338,000 tons) = 10 per cent of the pore space had been withdrawn up to 1920, there exists an initial "flush" stage, even in seepage-oil recovery with its wide oil-yielding surface, which, however, is gradually levelled off. These results may be very clearly observed in the production curves illustrated simultaneously.

(b) Flooding Tests

In this connection we should also discuss the brine flooding tests conducted in our research laboratory in the last years. It has been mentioned in the introduction that the edge-water level is absolutely constant, so that there exists no hydraulic pressure whatever. The viscosity of the crude amounting to 1,200 to 2,300 cp. at the prevailing reservoir temperature, is much higher than the value of 35 to 40 cp., which is usually given as standard upper limit for water flooding.

TABLE 5—Flooding Tests with Wietze Wealden Oilsand (March-Nov., 1951)

Test No.	Sand Filled into Tube	Temp. (° F.)	Pressure (atm)¹	Flow Velocity Water (cm³/cm²/h)²	Water-Oil Ratio	Time (in Days)	Oil Recovery (in %)
1	in situ	64	0.1	2.32	33:1	1	20.8
2	by hand	64	0.1	1.16	340	49	15.3
3	by hand	64	0.1	1.29	406	66	
4	by hand	64	0.1	0.72	199	65	23.8
6	by hand	104	0.1	15.13	643	20	40.4
7	80 atu¹	64	capill.	0.0054	1.5	181	32.0
8	by vibrator	64	capill.	0.0045	1.1	181	57.0
9	by hand	64	capill.	0.0068	3.2	181	37.6

¹To convert to lb. per sq. in., multiply by 14.2

²To convert to cu. in./sq. in./h., multiply by 0.39

The displacement tests were conducted in a sand-filled tube having a length of 3.28 ft. (1 m) and a size of 3.9" (10 cm). We need not discuss any details here, as the testing procedure is similar to that commonly used in the United States.

In test 1 the flooding tube was pressed into the sand in the mine at a pressure of 20 metric tons in order to simulate the natural conditions of bedding. It was impossible, however, to press it farther than 13 3/4" (35 cm). In tests 2, 3, 4, 6, and 9 the loose sand was pressed in by hand, in test 7 at 1,136 p.s.i., (80 atue), in test 8 it was shaken in by a vibrator which probably attained the tightest packing of all. A survey of the results is to be seen in Table 5. Test No. 6 was made at 104° F. (40° C.), all other tests were made at 64° F. (18° C.). Throughout the tests No. 1 to 6 the brine introduced from below into the vertical core-holder was held at a constant pressure of 1.4 p.s.i. As is indicated in the table, the flow rates were relatively high, especially at higher temperatures, i.e., they amounted to 0.27 to 6.13 cu. in. per hour and square inch (0.7 to 15.1 cm³ per hour and cm²). After 66 days at the longest, the volume ratios of the throughput water to the oil were very high reaching 33 to 643, the tests were completed, and an ultimate recovery of 15 to 40 per cent. had been attained. As expected, the best results were obtained at the highest temperature, though the required amount of water was also highest. In order to reduce this fast movement of the water the pressure of 1.4 p.s.i. was replaced by a very slow capillary rise of the water level in the tests 7 to 9. This reduced the flow rate to a fraction of about 1/400, the water consumption, however, also declined to 1/100 or 1/200. Instead, the duration of the tests was increased to more than six months. The most important result, however, was a simultaneous increase of the ultimate recovery which reached 37 to 57 per cent, i.e., it was highest in the sand sample that had been packed tightest by means of the vibrator.

These results, which may be regarded as important after all, have confirmed us in our expectations of being able cautiously to flood the suitable blocks without imposing any water pressure on them, rather by slowly raising the edge-water level, which would normally be constant at Wietze. At present we are conducting a semi-technical preliminary test at a hewed-out block in the mine having a height of 4.9 ft. (1.5 m) and a base of 10.7 sq. ft. (1 m²), the rise of the water level being checked by electrical logging in vertical intervals of 3.9" (10 cm). Eventually there will follow flooding tests with surface-active chemicals. It should be pointed out, however, that the brine of Wietze used for flooding has a very low surface tension of no more than 35 dyn/cm, while 72 to 76 dyn/cm are measured in other oil field brines as well as in fresh water. As regarded from the physical standpoint, it, therefore, seems to be a very suitable flooding medium.

(4) Oil Recovery and Drainage Problems in the Light-Oil Block of the Rhaetic Opened by Horizontal Wells

It was already pointed out in the geological section of this paper that the plane of overthrust is underlain by the autochthonous flank block containing light-oil-bearing sandstones of the Rhaetic (uppermost Triassic), which consist of pure consolidated fairly permeable sandstones dipping 55 to 65°, i.e., as steeply as in the upper block. The porosity is 18 to 25 per cent, the permeability 300 to 1,000 mdy. Even if these values are regarded as high, they are yet much lower than those of the Wealden with its porosity of 30 to 40 per cent and 1,000 to 20,000 mdy. These conditions are compensated by the different properties of the light oil, as may be seen from Table 3.

With its 43 to 60 cp. this oil possesses but a fraction of the viscosity of the Wealden oil of 1,200 to 2,300 cp., so that its flow conditions are much more favorable; moreover, the temperature also reaches about 82° F. (28° C.), so that the viscosity will even be a little lower than indicated in the table.

Soon after 1900 this reservoir at a depth of 1,148 to 1,312 ft. (350 to 400 m) was also discovered in the course of the intensive drilling campaign at Wietze described above, and up to the end of 1952 about 1,989,000 bbl. of light oil (300,000 tons) were recovered from it by means of normal vertical wells. The energy conditions were also more favorable here than in the Wealden, as this autochthonous flank block stood in contact with the edge-water and was subject to an active edge-water drive. Present reserves recoverable by wells are low, amounting to a mere 66,300 bbl., so that an ultimate output of about 2,122,000 bbl. might be expected, (10,000 tons and 310,000 tons).

In 1937, when about 1,824,000 bbl. (275,000 tons) i.e., 89 per cent of the total reserves had already been recovered and there was only a small residual production left, we started to drive a tunnel 2,300 ft. (700 m) long into the neighborhood of the Rhaetic deposit extending from the network of tunnels in the Wealden. From drilling-chambers three horizontal wells at a time were drilled slightly slanting upwards into the Rhaetic reservoir. 37 horizontal holes were drilled in all, with a total length of 10,200 ft. (3,120 m) and a length of 279 ft. (85 m) for each hole. 5,700 ft. (1,740 m) or 56 per cent are running through the oil-sandstone.

These horizontal holes yielded 106,100 bbl. (16,000 tons) from 1937 to 1952, there will be an eventual future addition of about 6,615 bbl. up to the end of the oil recovery period (1,000 tons). Though this total amount of 112,700 bbl. (17,000 tons) only forms a small percentage (5.3 per cent) of the 2,122,000 bbl. (310,000 tons) recovered by means of wells, it should be kept in mind that the actual flush period had long passed when the horizontal wells were started.

Though it is impossible directly to compare the seepage tunnels to the horizontal wells, we may yet draw the conclusion that seepage oil recovery is promising in reservoirs producing by gravity and containing heavy or light oil. No promising results may be expected from horizontal wells, unless a source of energy is available, as e.g., the edge-water drive in the Rhaetic, or unless the oil has a low viscosity, though even then, practically all of it could be recovered by deep drilling, unless the horizontal wells are drilled before deep vertical ones. In the latter case at least a small advantage would be noted on the side of the horizontal wells, which are a little less expensive.

(II) Pechelbronn Near Strasbourg in Alsace

The geological and reservoir conditions of the oil field of Pechelbronn will be discussed here only insofar as they are of interest with regard to mining. For further details refer to Schnaebele, 1948.[26] Acknowledgment is made to the officials of the S. A. Pechelbronn, Merkwiller (Alsace) and especially to Mr. Blanchard and Levy for the possibility of discussing with them the questions dealt with in the present report.

(1) General Geology and Production

In the Tertiary age the valley of the Upper Rhine had sunk in between the Variscian massives of the Black Forest and the Vosges developed towards the end of the Paleozoic age, forming a graben the center of which was filled with Tertiary sediments reaching a thickness of many thousands of feet. At the edges of this graben, which is 22 to 25 miles wide (35 to 40 km), there have formed fractured blocks with a flat dip of 4° to 8° that proceed in steps towards

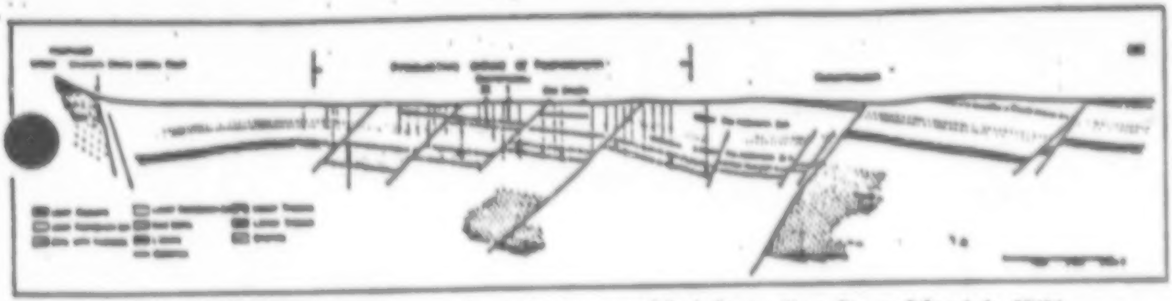


Figure 14—Geological section across the productive area of Pechelbronn. (According to Schnaebele, 1948.)

center and are bounded by mostly ithetic dislocations striking in the di- ion of the Rhine, i.e., northeast- hwest, (Fig. 13, 14). Especially at the tern edge, these dislocations have an iost importance as oil-traps for the ozoic or Tertiary oil migrating up- ds from the graben of the Rhine ley. Each of these blocks near Pechel- nn is oil-bearing in suitable sand izons occurring in its higher sections, le the lower have become inundated. : length of this field of fractured :ks—which is of especial interest to -is 16 miles, its width 4 to 6 miles. km and 7-10 km). The Mesozoic base verlain by fresh-water deposits of the :ene with a thickness of 558 ft. (170 , which are followed by a series of ean and limnic Oligocene sediments :2 (400 m) to 2,624 ft. (800 m) thick; latter contain the reservoir rock— P lbronn beds, consisting of con- t lternating sands and marls. rast to Wietze, the oil-bearing ids and sandstones are only lenticular ving an individual thickness of 7 to ft. at the most, (2 to 3 m). Their oth is 656 to 1,312 ft. (200-400 m).

We shall not discuss the exploratory :ivities in the Mesozoic carried out in :ent years with variable results.

The oil deposits of Pechelbronn — the me actually means "pitch well"—have en known since the fifteenth century. 1735 the first shafts were sunk by nd, in 1829 the first wells were drilled Pechelbronner Oelbergwerke A. G., nalgamated by Deutsche Erdoel A. G. 1906. In 1917 oil-mining was started, ien already about 5,305,000 bbl. (800,000 ns) had been withdrawn by wells. A tal of about 5,500 wells have been drilled at Pechelbronn to date, about 5,000 of them into the Tertiary. Of the approximately 3,000 producers, about 700, or 450 respectively in the Tertiary beds, are yet being produced. The cumulative output is approximately 19,854,000 bbl. (3,000,000 tons), 6,280,000 bbl. (947,000 tons) being due to oil mining and 13,-674,000 bbl. (2.1 million tons) to the drilling of wells. About 92 per cent of the latter figure (12 million bbl. = 1,-930,000 tons) were recovered from the Oligocene, 800,000 bbl. (125,000 tons) from the Eocene, and about 300,000 bbl. (45,-000 tons) from Mesozoic reservoir rocks. At present about 529 bbl. a day (80 tons) are produced by the Pechelbronn mine, while the daily production of the Wietze mine is 397 bbl. a day (60 tons).

(2) Reservoir Data

The oil sands are fine to medium-grained and similar to the oil sands of Wietze. As already mentioned, there exists no continuous reservoir, but rather a series of lenses with thicknesses of a mere fraction of one inch to about 7 to 10 ft. (1-3 m) for every individual lense.

The oil recovered from the Pechelbronn mine is of an intermediate paraffinic type with a gravity of 26° to 29° A.P.I. (0.890 to 0.900 spec. grav.), its flow properties evidently being similar to the light oil of Wietze (refer Table 2). So its flow reactions are much more favorable than those of the heavy oil of the Wietze mine, a fact which is of major importance as regards the seepage and drainage factors.

Owing to its properties as a light oil, it is no wonder that repeated blow-outs and explosions were reported of between 1780 and 1925. These were controlled only after small gas vent-holes had been drilled at the heads of the tunnels. The gas is 89 to 90 per cent methane, 7 to 13 per cent propane and lighter.

Though the water has a certain salt content, the latter is much lower than at Wietze reaching only 0.16 to 0.32 pounds per gallon (20 to 40 g/l), as is evident from the analyses illustrated in Table 3. A characteristic feature is the stadily growing salt content in greater depths. Since hardly any salt-content is noted at the near-surface, we may conclude that ample surface water flows are received.

Of especial interest are the temperatures and the geothermal gradients throughout the area of Pechelbronn. While a temperature of +104° F. (+40° C.) is measured at a depth of 2,950 ft. (900 m) in Northwest Germany the same as in the United States, this value will reach 194° F. to 230° F. (+90° to 110° C.) at Pechelbronn. This temperature being extremely high, we may calculate the gradients to attain 18 to 22 ft. per 1° F. (10-12 m per 1° C.), especially in the eastern direction towards the valley of the Rhine, while the normal values, that are also measured west of Pechelbronn, will be 46 to 64 ft. (25 to 35 m). In the shaft itself — which is here of interest to us as regards seepage problems—the temperature reaches about 86° F. (+30° C.); this increase of about 18° F. (10° C.) as compared to Wietze will be of benefit to all flow processes.

Before discussing the drainage problems, we should only say a few words about the reservoir energy. The reservoir chiefly drains by gravity the same as at Wietz, though long before the start of mining gas had formed an important component of the drive. When mining was started, however, the same sub-surface phenomena were observed as a bit later at Wietze. The higher western sections of the reservoir had been substantially depleted by the cumulative withdrawal of 5,305,000 bbl. (800,000 tons) by means of wells, while the lower sections overlying the horizontal zone of transition to the edgewater showed an improved oil content. The water content of the transition zone ever-increases in the downward direction towards the pure water sandstone. In contrast to Wietze a weak edge-water drive may be noted, resulting in respective phenomena of water encroachment. The degree of this water encroachment is not so high,

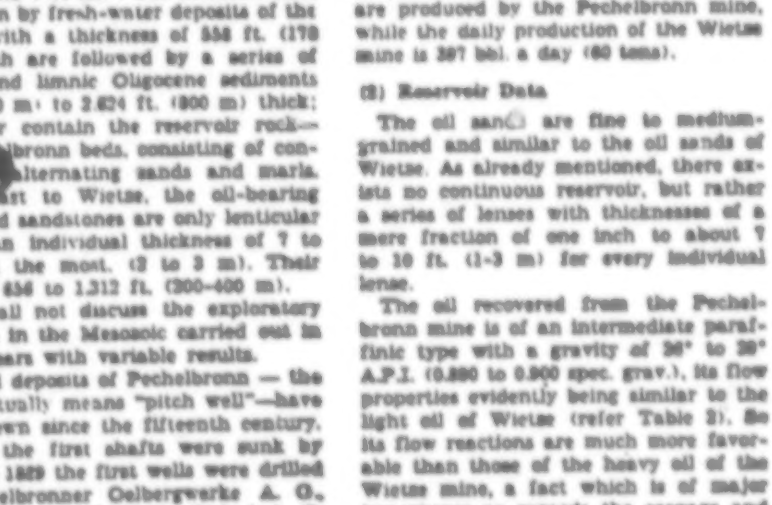


Figure 13—A: Tectonic Map of the Upper Rhine Valley. (According to Schnaebele, 1948.)
B: Faulted Tertiary Blocks at Pechelbronn. (According to Schnaebele, 1948.)

however, that the mining operations are likely to be disturbed by it.

(III) Heide in Holstein

The geological situation of the Heide field is evident from Fig. 15.

The Province of Holstein is criss-crossed by a number of elongated salt domes, in part, more than 60 miles long (100 km), striking north-northeast - south-southwest. On the western flank of the salt domes of Heide oil deposits have long been known in the white chalk at the shallow depth of 164 ft. (50 m), which, in 1935, led to the discovery of a number of oil fields at a depth of 2,630 ft. (800 m) to 5,580 ft. (1,700 m). Up to the end of 1952, 9,768,000 bbl. of crude (1,473,000 tons) had been recovered from the limestones and sandstones of the Middle Zechstein, the Upper Dogger, and the Lower Cretaceous. At present we are intensifying our exploratory activities and geophysical investigations especially off the coast in the flats of the North Sea.

The white chalk of the overlying Senonian was lifted up simultaneously with the salt dome and became interspersed by dislocations with small throws.

The Senonian is covered by Tertiary and Diluvial shales and sands. Besides, at the top of the salt dome, the Diluvial beds have broken down in the form of a graben.

The uppermost sections of the Senonian are impregnated with highly viscous oil probably coming from the flanks, that migrated upwards along the breaks and accumulated below the Tertiary and Diluvial overburden or dislocations. For this reason, we find all grades between a white completely water-soaked chalk at the base and a light oil-chalk with a thickness of 33 to 66 ft. (10 to 20 m) as well as an oil content of about 5 per cent by weight, and above it a dark oil-chalk up to 164 ft. (50 m) thick with an oil content of more than 20 per cent by weight.

The water content in the pores decreases from a water saturation of 100 per cent in the white chalk to 2 per cent of the pore spaces in the rich oil chalk. The immigrating oil has, therefore, been able to displace the water up to the optimum value of 2 per cent of the pore spaces. It should be surmised, however, that the aging or polymerization processes to which the oil has been subjected and by which it has attained its present highly viscous state, did not take place before it had migrated into its present reservoir.

The inner structure of the chalk (93 per cent lime, 7 per cent shale) should be envisaged as a finely-branched latticed network of lime skeletons originally organogeneous in nature. They are quite different from a sand consisting of quartz grains. On the one hand, this explains why the porosity of the chalk is 43 to 48 per cent, and why, on the other hand, this inner structure will very easily collapse when subjected to increased forces of compression or tension, i. e., the chalk may easily become plastic. This property is very troublesome in mining, as considerable engineering manipulations will be required with regard to the walling. This plasticity, i. e., the absence of an inward stability, is a characteristic feature of the chalk.

Furthermore, the inner latticed network structure of the chalk provides a large surface. If it is further considered that, according to Table 2, the gravity of the oil is 14° to 18.3° A.P.I. (0.945-0.980 spec. grav.) and its viscosity 2,000 to 5,000 cp. at reservoir conditions, it is no wonder that no oil can seep out of the oil chalk. No seepage oil recovery by enlargement of the oil-yielding surface has, therefore, been known at Heide in the way of the seepage tunnels at Wietze and at Pechelbronn. The oil is held back and will not flow by gravity. So we had to restrict our operations to the excavation of the oil-chalk and to its low-temperature carbonization below the surface.

The following will also serve to characterize the oil-chalk. We have made tests with hydrochloric acid in order to dissolve the lime skeleton. The permeability that had been high before, was immediately reduced to a mere fraction of its original value, as a mud developed that consisted of insoluble components. Tests are yet in progress in order to determine the feasibility of an oil recovery on that basis.

(IV) Attempt of Comparing the Efficiency and Ultimate Recovery of Two Different Seepage Methods at Wietze and at Pechelbronn

It is difficult to compare Wietze to Pechelebronn because there are wide differences in the petrographic and chemical properties of both reservoirs.

Wietze has a relatively uniform sand series, while the series of Pechelbronn either consists of a single or of several isolated or overlapping sand-lens Though the Wietze deposit is poorer [illegible] energy, its uniform sandstone properties may be valued as a positive factor. On the other hand, having 8 to 11 times viscosity value as the crude of Pechelbronn, the Wietze crude is much less suited for all processes of seepage or gravity drainage. The impression is gained that this chemical factor has an extraordinary weight, so that the reservoir of Pechelbronn is sure to reach a high ultimate recovery.

The outward development of both fields is very similar, as both were intensively produced by wells in 1875, while mining was started by the same company in both fields in 1917 and 1920 respectively. Pechelbronn, however, proved bigger than Wietze. Its productive area comprises 6,178 acres (2,500 ha) as against 266 acres (110 ha) at Wietze, that have been exploited by wells. The mining areas cover 4,349 acres (1,760 ha) (in 1949) or 124 acres (50 ha) respectively at Wietze.

These 6,178 acres (2,500 ha) or 4,349 acres (1,760 ha) respectively though, represent the sum of all surfaces in the sand horizons overlying one another with an individual thickness of but 3.28 to 9.84 ft. (1-3 m), while the sand series of Wietze of 266 acres (110 ha) has a thickness of 82 ft. (25 m). At an average

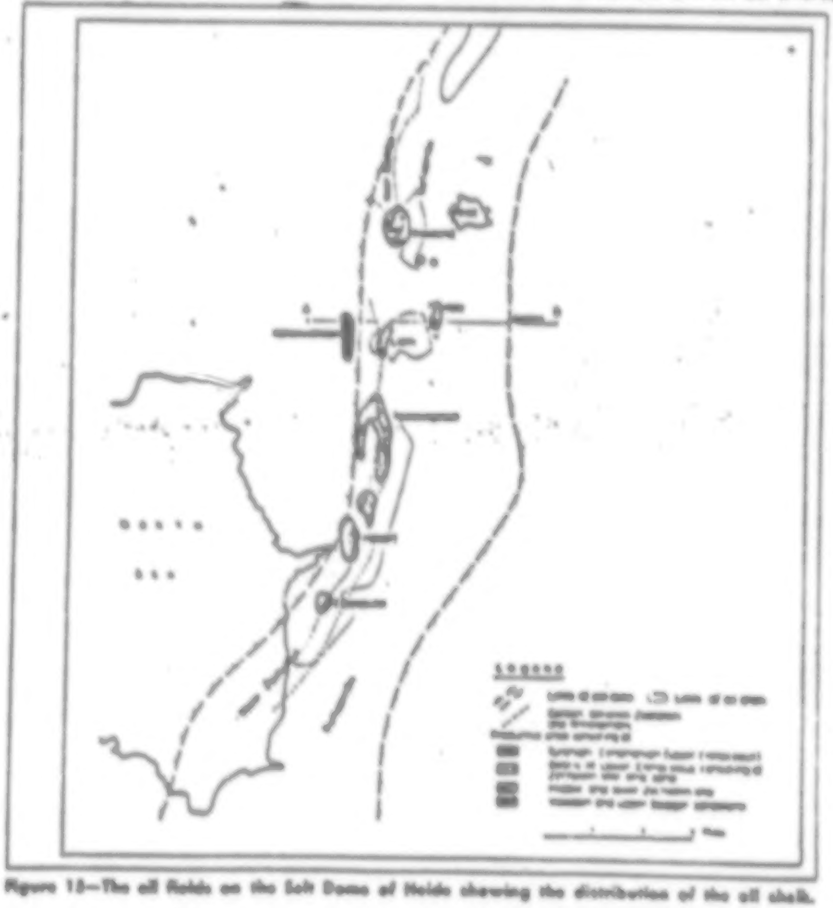


Figure 15—The oil fields on the Salt Dome of Heide showing the distribution of the oil chalk.

thickness of 6.6 ft. (2 m) at Pechelbronn,

$$\text{about } 6{,}178 \cdot \frac{6.6}{82} = 494.2 \text{ acres (200 ha)}$$

may be compared to the 286 acres (110 ha) at Wietze.

While drilling in the Wealden ceased [illegible]tze after about 480 wells had been [illegible]ted, Pechelbronn has more than 3,000 wells, so that at Wietze there are 1.7 wells per acre (4.4 wells per ha) while in the same horizon of Pechelbronn there are only about 0.016 wells per acre (0.4 wells per ha).

If the whole oil content of Pechelbronn at a pore space of 25 per cent is calculated at 8,290,000 bbl. (12.5 million tons), only 6 to 7 per cent of this amount, namely 5,305,000 bbl. (800,000 tons) had been recovered until mining was started, while Wietze had produced about 10 per cent up to that date. These 2,240,000 bbl. (333,000 tons) = 10 per cent recovered at Wietze correspond to about 64 per cent of the whole recovery to be anticipated by drilling, while the 5,305,000 tons = 6 to 7 per cent of the Pechelbronn reserves are certainly equivalent to no more than 20 to 25 per cent of the anticipated recovery by wells. (Up to 1952 Pechelbronn had recovered 12.6 million bbl. (1.9 million tons) by drilling, and it is at present producing 12,600 bbl. (1,900 tons) to 13,200 bbl. (2,000 tons) as against 1,697 bbl. (200 tons) a month at Wietze.)

These figures are to show that, before mining was started, the drainage by wells had been much more intensive at [illegible] than at Pechelbronn, and that [illegible]rvoir of Pechelbronn had at that time by no means reached the advanced stage of depletion of the Wietze field, so that, as compared to Wietze, a distinct advantage should be attributed to Pechelbronn with regard to mining and to seepage recovery.

And what are the results today? At a first glance Wietze has a much closer tunnel spacing of 1,326 ft. per acre (1,130 m per ha) than Pechelbronn with its 263 ft. per acre (220 m per ha). This need not be interpreted as a drainage advantage for Wietze, since the deposits at Wietze are about 10 to 15 times as thick as those at Pechelbronn, so that the workings can be driven in several stories one above the other. Furthermore, it is at all impossible to compare both figures, as at Pechelbronn, the tunnels had been driven into the oil sand itself only between 1917 and 1923, while they were later driven into the overburden, and the deposits were exploited by shafts of 2.0 x 2.0 ft. (0.6 x 0.6 m) at intervals of about 33 ft. (10 m).

This consideration leads us to the characteristic comparison of the actually oil-yielding seepage surfaces which, at Wietze, will reach 646 sq. ft. for a length of 33 ft. (60 m^2 for a length of 10 m) (without the bottom, as the oil does not seep upwards), while they are only 54 sq. ft. (5 m^2) at Pechelbronn. An area of 1 acre has, therefore, an open seepage area of 271,900 sq. ft. (60,000 m^2 per ha) at Wietze, though only 475 sq. ft. per acre (110 m^2 per ha) at Pechelbronn. This would at first be considered as a great characteristic advantage of Wietze, though the size of the "drainage areas", the "oil-yielding background" has been quite disregarded for the present. Later on (refer Part C) we shall find the figure of 2,839 cu. ft. of oil sand (246 cbm) corresponding to 1 ft. (or 1 m respectively) of seepage tunnel at Wietze (a surface of 197 sq. ft. per 1 ft. or 6 m^2 per 1 m). In other words: At Wietze 1 sq. ft. of seepage tunnel corresponds to 134 cu. ft. of oil sand (1 m^2 to 41 m^3), as against 594 cu. ft. per 1 sq. ft. (182 m^3 per 1 m^2), (at Pechelbronn 20,000 m^3 per 110 m^2). It may thus be concluded, that the Wietze oil sand has been drained more intensively than at Pechelbronn, that it is imperative to drain it more intensively, since the oil is much more viscous than at Pechelbronn.

Up to 1952 Wietze had produced 3.6 million bbl. (543,000 tons) of seepage oil against 6,280,000 bbl. at Pechelbronn (947,000 tons). These amounts had been recovered from 186,960 ft. (57,000 m) of seepage tunnels with a seepage area of 3,693,000 sq. ft. (342,000 m^2) at Wietze, and from about 25,000 shafts with a seepage area of 1,350,000 sq. ft. (125,000 m^2) at Pechelbronn plus from about 1,080,000 sq. ft. (100,000 m^2) of 59,000 ft. (18,000 m) of seepage tunnels driven into the oil sand itself between 1917 and 1923. This gives an output of 0.98 bbl. of oil per sq. ft. of seepage area (1.6 tons per 1 m^2) at Wietze and 2.57 bbl. at Pechelbronn (4.2 tons). If it is considered that in 1952 about 189,000 bbl. (28,200 tons) of seepage oil were produced at Pechelbronn against about 120,000 bbl. (18,100 tons) of seepage oil at Wietze, i. e., that the Pechelbronn reserves are doubtless greater than those of Wietze, the difference of the seepage oil output per 1 sq.

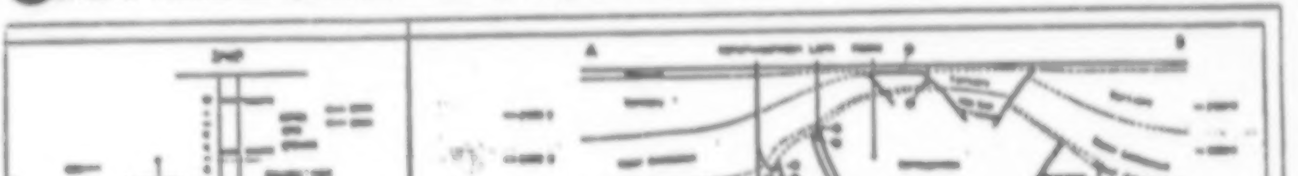

Shaft
A
B
Cross-Section of Heide Shaft with Oil, Gas and Water Contents
(according to Doscher Wix)
Section across the Saltdome of Heide
Section across the Heide Oilchalk

Figure 16—Cross-sections of Salt Dome of Heide (upper part) and oil chalk deposit.

ft. of seepage area would certainly even become greater up to the end of seepage-oil mining and the relationship would then probably amount to 3:1 in favor of Pechelbronn.

The causes of these differences can only be surmised. Since in the calculation of the factor of "seepage-oil output per 1 sq. ft. of seepage area" any differences of the applied engineering methods may be neglected, it may certainly be assumed that the greater advantage to the Pechelbronn reservoir had been caused by the fact that the reservoir had not been so largely depleted at the start of mining as the Wietze field, and that the viscosity of the oil only reached about 10 per cent of that of the Wietze oil.

It is important from the aspect of the final economic considerations to regard the values of output per 1 acre or per 1 foot of seepage tunnel. The former value is:

1,287 bbl. per acre (480 tons per ha)
at Pechelbronn up to 1949,
29.144 bbl. per acre (10,860 tons per ha)
at Wietze up to 152,
42.489 bbl. per acre (15,860 tons per ha)
at Wietze up to the end.

The latter value is:

4.3 bbl. per ft. (2.2 tons per m)
at Pechelbronn up to 1952,
18.5 bbl. per ft. (9.3 tons per m)
at Wietze up to 1952,
24.5 bbl. per ft. (12.2 tons per m)
at Wietze up to the end.

The above figures have an importance only from the economic aspect. They can be applied to drainage problems only when referred to 1 ft. of oil sand thickness. In that case there are

195 bbl. per acre-foot (240 tons/ha/m)
at Pechelbronn up to 1949,
352 bbl. per acre-foot (434 tons/ha/m)
at Wietze up to 1952,
518 bbl. per acre-foot (634 tons/ha/m)
at Wietze up to the end.

This "improved depletion" at Wietze, however, is only apparent insofar as, as mentioned above, one square foot will correspond to 134 cu. ft. (41 m³ per 1 m²) of seepage space at Wietze, against 594 cu. ft. per sq. ft. (182 m³ per 1 m²) at Pechelbronn, so that for 1 acre at Wietze there are required in order to reach this result 271,900 sq. ft. per acre (69,000 sq. m per ha) and 475 sq. ft. per acre (110 sq m per ha) at Pechelbronn (1,311 sq. ft., if the seepage tunnels driven into the oil sand between 1917 and 1923 are included). We shall conclude by once more pointing to the above mentioned difference between the viscosities of the crudes of Wietze and of Pechelbronn.

(B) Engineering Section

I. General

The idea of recovering oil by mining was based upon the consideration that, if the surface in a heavy-oil reservoir poor in energy is enlarged, the oil is given a better opportunity of leaving the reservoir. If oil is recovered by drilling wells, merely relatively small round areas, depending upon the respective depth, are opened to the outflow of oil. It is obvious that, if tunnels with a cross-section of about 6.5 times 6.5 ft. are driven into an oil reservoir, the much more extensive area of seepage will be of benefit to the outflow of the oil. In this connection it is of extreme importance that, in oil-mining, the oil reservoir in its natural rock surroundings becomes accessible to scientific engineering research to a degree that could never be reached by the drilling of wells.

The knowledge hitherto obtained has stimulated us to seek in oil-mining the further possibilities of a most complete depletion of all oil reservoirs. Attempts of solving the problems of oil-mining have been made not only in Europe, Asia, and the United States, but also in Canada, in the area of the Athabasca oil sand deposits, where the biggest reserves of all are awaiting their utilization.

Oil mining in Germany has been chiefly developed by the pioneering ventures and engineering experiences of Deutsche Erdoel-Aktiengesellschaft (DEA). No technical data had been available that might have been resorted to, so that all operations had to be slowly developed on the basis of new ideas, considerations, and tests.

In the course of years the following shafts have been sunk for oil-mining:

Pechelbronn/Alsace	7
Wietze/Hanover	2
Heide/Holstein	2

As is evident from the geological section of this report, the reservoirs of these three oil-mining areas are not only located in different geological formations, but they also exhibit different petrographic properties. There are medium-hard sandstones of the Tertiary at Pechelbronn as well as loosely cemented sands, while Wietze only possesses loose sands of the Wealden, and at Heide, the oil is contained in the chalk of the Senonina. Light oil is recovered in Alsace, heavy oil along with small amounts of light oil at Wietze, heavy oil is produced at Heide.

The different character of the reservoirs and the crudes involves different mining methods, so that we may, on the basis of these three mining areas, present valuable experiences and give advice and directions for future oil-mining projects.

Schlicht[1, 11] distinguishes between indirect and direct oil-mining methods.

The indirect recovery consists of driving tunnels or drilling holes outside of the reservoir itself, into the beds overlying or underlying the reservoir, from which the reservoir rock is tapped by underground shafts or subsurface wells.

Direct mining comprises all methods of driving tunnels into the reservoir itself in order to make the reservoir rock yield up its oil content by free seepage, or of excavating the reservoir rock, hoisting it to the surface, and processing it with the aim of separating the rock from its oil content.

Both forms of mining have their characteristics and their special significance. Their application is based on certain assumptions, chiefly as regards safety, the readiness of the reservoir for mining and its technical mining possibilities. It is certain that a reservoir with gas or water pressures of 284 p.s.i. cannot be directly mined. How many oil fields are there in the whole world though, with high pressures in the beginning, tha later lose their pressures and becom practically pressure-less in the course of the primary production stage! Such reservoirs have become ready for mining, which means that it has become possible to work below the surface. Of course there are certain transitional stages with occasional gas blowouts from the reservoir, as e. g at Pechelbronn and at Heide. Insofar as these phenomena can be controlled and the mining safety is not endangered by them, they may be regarded as of minor importance. As already mentioned, the state of readiness for mining is reached through the primary depletion of the reservoir by means of wells. In other reservoirs these problems may be more easily solved by indirect mining than by driving the tunnels directly into the oil reservoir. The reservoir rock may e. g. be tapped from tunnels in the overburden or in the underlying beds and in the meantime one may achieve the required degree of safety and readiness for direct mining. Frequently, as e. g. recently at Pechelbronn, this method has also resulted in a quite considerable financial advantage.

Though it is frequently possible to drive tunnels into the oil sand itself, as the reservoir will have attained a certain readiness for mining, this need not apply to the large-scale mining of the o sand by excavation of large areas or spaces. At Wietze it is possible to mine the oil sand by excavation only after its depletion by seepage tunnels, i.e., when the oil content, after the 15 per cent recovery by means of wells, has sunk by further 25 per cent through the seepage of tunnels. Oil-sand mining by excavation without previous seepage may be dangerous or quite impossible.

Furthermore, the decision whether to use indirect or direct mining methods is dependent upon the properties of the reservoir rock. Hard reservoir rocks, as e. g. in the Rhaetic at Wietze, may more easily be drilled into than excavated in mining. Porous and highly permeable sands or limestones are more liable to an indirect method of recovery by means of subsurface drilling or to direct seepage-oil recovery than to direct oil-sand mining by excavation.

Loose sands are less easily controlled in mining, so that it is advised to use in them an indirect method of mining.

Of decisive importance is the quality of the oil or its viscosity. Only highly viscous oils will induce the mining engineer to resort to oil-mining by excavation and subsequent washing of the oil reservoir itself, as with heavy oil mining will probably be preferred, unles the direct driving of tunnels into the oil reservoir itself, as with heavy oils, will lead to a recovery of seepage-oil, which involves much larger oil-yielding surfaces.

Even these few examples show that there may exist any transitional stages,

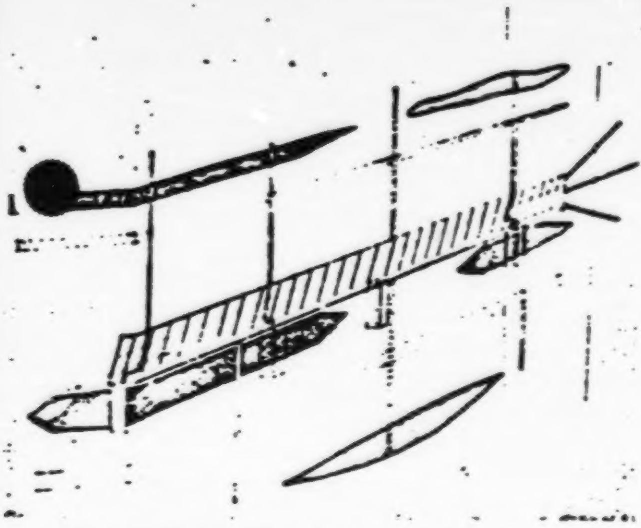


Figure 17—Diagrammatic view of seepage oil recovery at Pechelbronn (Alsace).

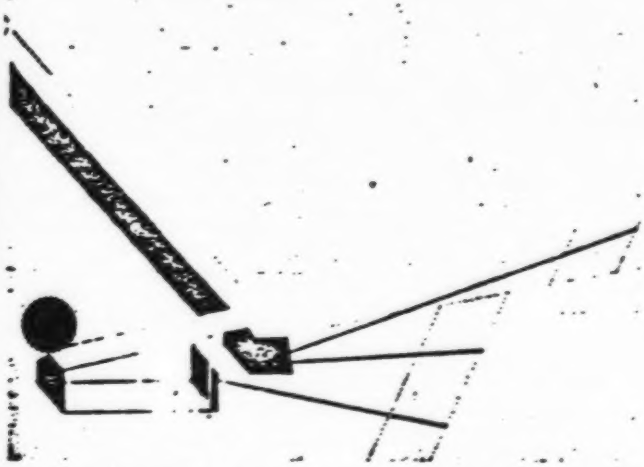


Figure 18—Diagrammatic view of seepage oil recovery by wells drilled below the surface in the light-oil area of Wietze.

Figure 19—Mine of Wietze with topping and vacuum plants.

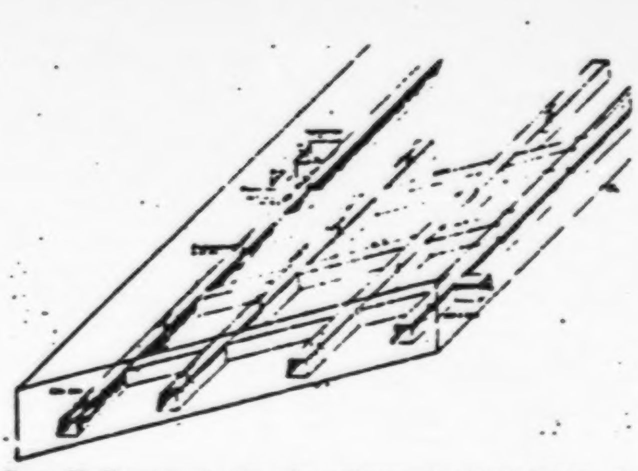


Figure 20—Diagrammatic view of tunnel network with flat-bedding in the oil mine of Wietze.

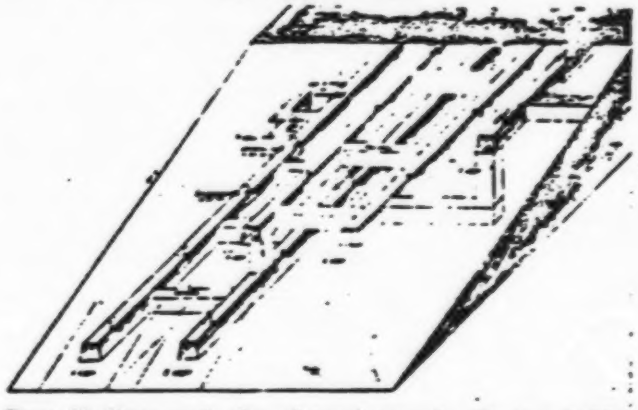


Figure 21—Diagrammatic view of tunnel network with steep bedding in the oil mine of Wietze.

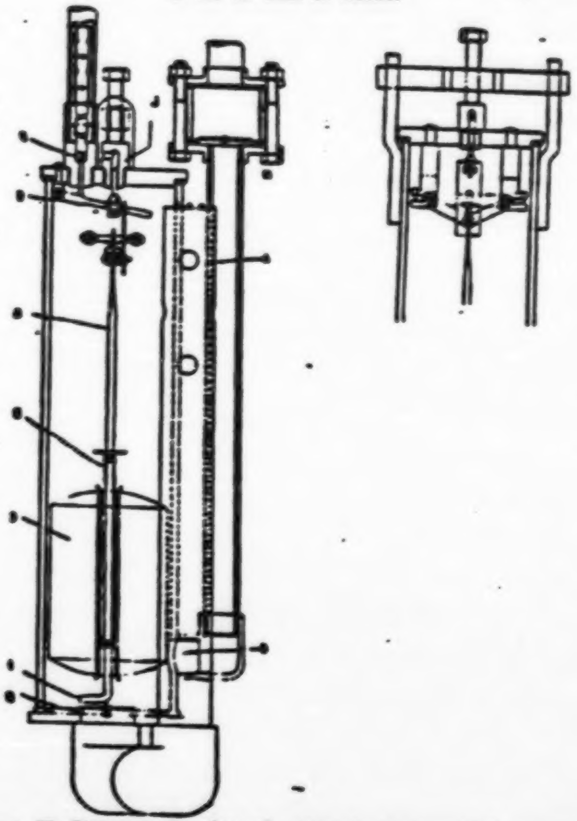


Figure 22—Diagrammatic plan of automatic compressed-air apparatus (Iron Miner) oil mine of Wietze.

and that the optimum method is not always applied from the very start. It is possible, however, without any difficulties to pass over from one method to the other. In any case it is already evident that direct oil-sand mining by excavation should be started only when the drainage efficiency of other methods has become too poor, or if quite different aspects of social economy will induce us to assume a positive attitude towards mining. In the economic section of this report these aspects will be dealt with in greater detail. Our present high standards of primary and secondary oil recovery methods have yielded us so many experiences and suggestions that may be of great benefit to oil-mining.

The following may be said about the history and development of oil-mining:

II. Indirect Mining

(1) Pechelbronn[23]

Already in 1735 oil-mining had taken its start with the discovery of the Pechelbronn reservoir. A Swiss operator acquired rights of exploitation and had a tunnel driven. About 10 years later shafts were sunk by hand down to a depth of about 89 ft. (27 m). Up to 1785 ten of these hand shafts had already been sunk. Besides, two further tunnels were started.

About the middle of the eighteenth century the lease passed into the possession of the French family Le Bel, who kept up this primitive mining method. Up to 1888 about 15 further hand shafts were sunk to a depth of 312 ft. (95 m). The total length of the tunnels extending from these hand shafts was about 28 miles. Total output about 149,000 bbl. (22,400 tons) comprising 92,800 bbl. (14,000 tons) of seepage oil.

Up to 1867 the oil had been recovered by a direct mining method—the washing of the excavated oil sand in a surface plant. In about 1875 this method was basically changed. When the tunnels were enlarged and began to yield increased amounts of seepage oil the washing of the oil sand was discontinued. This was accompanied by gas and water intrusions that greatly endangered the safety of the mines and caused much trouble to its management. At that time it was not tried to overcome these difficulties. so after numerous accidents, explosions, innundations, the refusal of the crews to descend, etc., oil recovery by mining was altogether stopped. Oil was then recovered by means of wells from the field of Pechelbronn that had been explored in the meantime. Though it may seem absurd, the old mine of Pechelbronn had been closed down not owing to the depletion of its deposits, but because by these rich deposits the mine management had been confronted with almost insoluble tasks.

In 1906 Deutsche Erdoel-Aktiengesellschaft took over the Pechelbronn lease and proceeded with the recovery of oil by drilling wells. About 10 years later oil-mining was additionally resumed in a modern form.

Noellenburg, then general manager of Deutsche Erdoel-Aktiengesellschaft, had the first shaft sunk to a depth of 492 ft. (150 m), from which the driving of tunnels was started. Recovery set in in April, 1917. Early in 1918, because of favorable exploration results, the shafts II and III were sunk to a depth of 656 ft. (200 m), from which tunnels were driven into the field.

When Alsace-Lorraine was lost to the Germans in 1919, these three shafts were given over to the French in an undamaged condition. So far this was the end of the mining activities of Deutsche Erdoel-Aktiengesellschaft in Alsace. Later on the French erected double pit plants by enlarging the existing shafts I, II, and III through sinking the shafts IV, V, and VII.

In the modern oil mining of 1917 the tunnels were also directly driven into the reservoir itself, i. e., here again the method of direct mining was pursued. Soon, however, the French management of the mine departed from this procedure by driving the tunnels into the overburden and thus resorting to an indirect method of recovery. The partly lenticular oil reservoirs were tapped by drill holes or underground shafts with small cross-sections of no more than 23" x 23" (60 x 60 cm) and the oil accumulating in them was withdrawn by automatic suction apparatuses and pumped to the surface through a network of lines, a procedure that has been continued to date (Fig. 17). The reasons and considerations leading to the decision to stop driving the tunnels through the oil reservoir itself were of a technical nature and may be summarised as follows:

The reservoir partly consists of sandstones that are not so easily recoverable as loose sands. In many cases the sandstones would have to be loosened by shooting, which is rather dangerous. Furthermore, losses of gas were to be prevented in order to utilize the gas as driving energy. The dangers of gas blowouts had to be avoided, as high pressures would be expected in closed oil-sandstone lenses and lastly the timbering of the mines should not be greased with oil in order to avert the dangers of a fire. The tunnels in the adjacent rock were lined with wooden tunnel frames that entirely sufficed for the prevailing pressure conditions.

In 1940 Deutsche Erdoel-Aktiengesellschaft had the second opportunity of taking over the Pechelbronn works, this time as trustee.

The shafts that had been damaged in the course of the war events were restored and production was again resumed. In 1945 at the end of the war Pechelbronn again passed over into the hands of the French—undamaged. The method was modified in 1951, insofar as the driving of tunnels was greatly restricted and replaced by the drilling of almost 1,000 subsurface holes, i. e., the thin sand layers were penetrated from all sides. The output again rose and consequently the production costs were considerably reduced. It is to be hoped that Pechelbronn will thereby have entered a new and most interesting stage of exploitation, especially if the possibilities of combining these methods with secondary methods of recovery are being considered. At present we are in a relationship of friendly exchange of thoughts and experiences with the administration of this French mine, by which the progress of mining will certainly be benefited.

The total length of the network of tunnels was about 253 miles (421 km) by the end of 1952. Up to the same date the total recovery from the mine amounted to 6,279,000 bbl. (946,847 tons).

(2) Light-Oil Recovery by Horizontal Wells at Wietze

In connection with the indirect mining of Pechelbronn, we should like to mention the indirect mining method of horizontal subsurface wells applied in a section of the Wietze field, namely in the hard sandstones of the Rhaetic already mentioned in the geological section. Its reservoir rock is a very hard calcareous sandstone interspersed with pyrite. It is impossible to drive tunnels into this hard rock without taking recourse to shooting. As this rock contained light oil, the utmost caution had to be observed. In order to avoid shooting, it was decided to drive a tunnel on the strike in the overburden and to drill holes radially extending into the reservoir from drilling chambers. The oil flowing out of these holes was pumped to the surface through a network of pipe lines. Owing to their limited extent, these operations only yielded a total of 112,000 bbl. of light oil (17,000 tons) from 10,220 ft. (3,116 m) (37 wells of 164 to 574 ft. (50-175 m) with a size of two inches at the end). (Fig. 18.)

III. Direct Mining

(1) Wietze

(a) General

As already mentioned in the geological section, the oil recovery at Wietze had already been started in 1858, and from the Wealden by the middle of the seventies. 40 years later it was recognized that the primary depletion of this heavy-oil reservoir had been very incomplete, because, as also already mentioned, it consists of rootless tectonic blocks which have no edge-water drive whatever. The edge-water is absolutely constant below the oil.

By increasing the oil-yielding surface we had hoped considerably to improve the possibilities of flow, and in May, 1918, a shaft with a depth of 853 ft. (260 m) was sunk. (Fig. 19.) At 728 ft. (222 m) and especially at 807 ft. (246 m) main cross-cuts were started to the north and to the south, and, extending from the latter the further network of tunnels was driven in the range of the reservoir itself. A ventilation shaft 748 ft. (228 m) deep serves the purpose of venting the foul air from the main shaft.

(b) Methods of Subsurface Mining Seepage-Oil Recovery

It now became possible to intensify the seepage recovery from the reservoir that had, in part, already been depleted. It was not easy, however, to find the mining solution to this problem. The timbering of the galleries that were subject to pressures from all sides met with ever-new difficulties, which, however, could be overcome in place after [illegible]ough check of the working condi[illegible] The first attempts were made with wooden tunnel frames, then all kinds of timbering and walling methods used in mining were resorted to — without any success, however. Only after long years of trial, the most advantageous walling proved to be the closed rigid trapezoidal iron frame. This walling made possible the descent into the mine without any major difficulties as well as the start of economic seepage-oil recovery. It is evident from the foregoing that when driving tunnels into the quicksand-like loose oil-sand under pressure, rigid walling made of iron proved most suitable. Though pressure effects will arise in the course of time, the tunnels will remain usable for an average of 20 to 25 years.

The oil sand deposits are intersected by tunnels running along the strike to the rise or dip and are as far as possible approached from the underlying beds, so that drainage squares are developed. Depending upon the dip of the reservoir, two different methods may be considered. With flat bedding, tunnels and sub-levels parallel to the latter are driven to the dip. (Fig. 20.) With steep bedding the tunnels are driven along the strike and are connected by cross-cuts and rises. (Fig. 21.) The cross-section of a seepage tunnel is about 37.8 sq. ft. (3.5 m²). Iron supports are set at intervals of 1.97 to 2.30 ft. (0.60-0.70 m); The roofs and supports have to be lagged with planking 1.17" to 1.56" thick, in order to prevent the exposed oil sand, which soon commences to seep oil, from mudding-off the tunnels. If the oil sand happens to be extremely wet, a wainscotted breast should also be used.

When driving the tunnels, wooden boxes or large-sized perforated pipes are set at definite intervals along both faces of the tunnels, or small shafts are sunk to catch the oil that seeps out of the exposed sand. From these gathering points to which all additional oil collected by hand in the tunnels is also conveyed through gutters, the oil is automatically pressed into a gathering pit by means of a pressure-apparatus. The oil entering the apparatus raises a float which in its turn opens a valve that admits air compressed to 42.6 p.s.i. (3 atue), by the latter the oil is pressed into the oil line. This apparatus has been developed by one of our engineers. Hardly requiring any maintenance at all, it saves labor and achieves a considerable rationalization of the operations. For this reason we have called it the "Iron Miner." 240 of these apparatuses are being operated at present. (Fig. 22.) (Producers Monthly, August, 1953, page 34.)

Oil sand excavated incidental to driving the seepage tunnels is hoisted to the surface (refer below) and processed along with oil sand produced from underground oil-sand mining operations. Up to late in 1952, a total footage of 231,850 (70,686 m) had been driven in seepage tunnels, of which 84,601 ft. (25,793 m) are still open. This footage has yielded a total of 3.6 million bbl. of seepage oil (543,000 tons), so 1 foot tunnel length will yield 18.6 (about 9 tons).

The operation technique of seepage oil recovery is evident from Figs. 23 to 27.

Mining of Oil Sand

When free seepage of oil has ceased, part of the oil is yet left behind in the reservoir. According to our experiences, the galleries become "dry" after a few

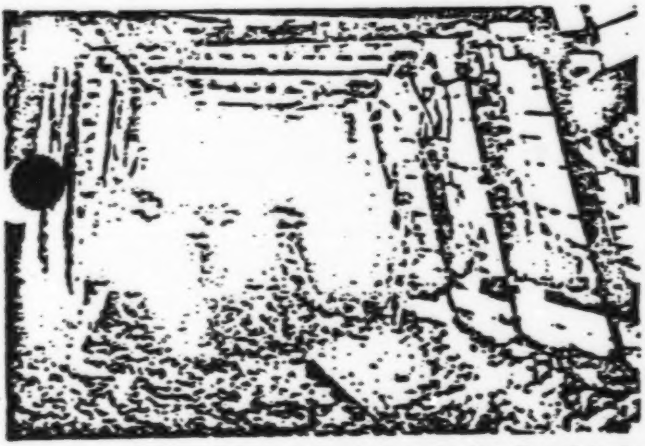


Figure 23 — Driving of seepage tunnels into the dry oil sand in the mine of Wietze.

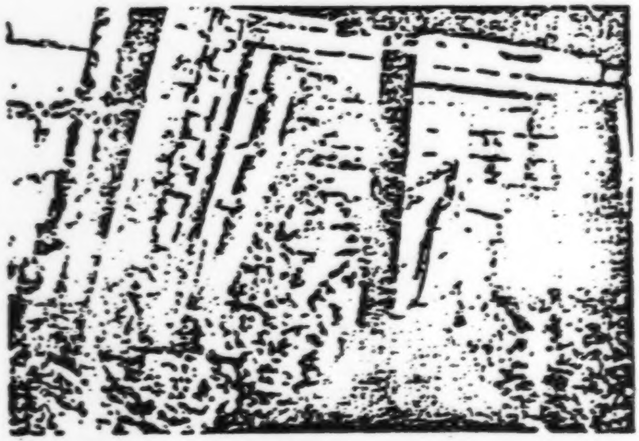


Figure 24—Driving of seepage tunnels into the wet oil sand of the Wietze mine by use of a wainscotted breast.

Figure 25—Driving of seepage tunnels. Breakthrough of wet oil sand section from the roof. Oil mine of Wietze.

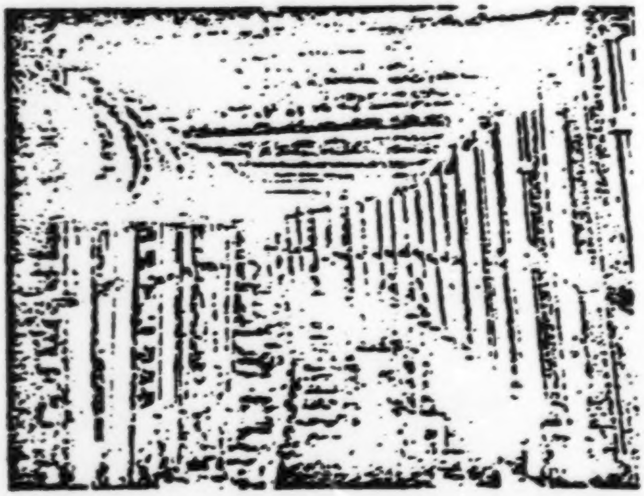


Figure 26—Finished seepage tunnel with gutters. Mine of Wietze.

years, though laboratory analyses have indicated that this "dry" oil sand yet possesses an oil content of 8 to 12 per cent by weight = 60 per cent of the pore space, so that complete exploitation is only possible by excavating the reservoir rock. The oil sand is excavated in those sections only that have already, in part, been depleted of oil and gas by previous seepage. Excavation without previous seepage might be either dangerous or absolutely impracticable in a virgin reservoir of quicksand-like characteristics where wide areas have to be exposed. The mining operations are made to advance in shortwall cuttings on the strike and solid backfill is used in bank-work.

From an overhand haulage-way that is driven into the center of the mining area, faces 8.3 ft. high (2.5 m) and 230 to 330 ft. long (70 to 100 m) head out into the field in the direction of both wings, the workings having first been secured by a safety-pillar. Headways for haulage or ventilation are advanced at the lower and upper ends of the faces. The support consists of the spiling commonly used in Germany along with 6 2.5" to 7 4·5" (17-20 cm) props and bars. The roof is wainscotted with 2"-piling. In order to secure the breast a so-called "mountain leg" is left standing in each working area of 9.8 ft. (3 m) length. This so-called "leg" is excavated only after the support has been fixed in place. In rather loose sands the face is secured by wainscotting. The oil sand is broken loose by means of pneumatic picks; stone intercalations are removed by shooting, with observance of all precautions.

Figs. 28 to 33 illustrate the excavation of the oil sand.

Transportation is accomplished by conveyor belts. From the latter, which are charged by hand, the excavated material will run along the lower tunnel belt, pass on to the overhand belt, and will then be dumped into a chute running into the main-road; here it is charged into haulage mine cars and conveyed to the surface.

The back-fill which consists of washed oil sand mixed with sawdust, is dumped down from the surface through a bore-hole especially drilled for this purpose or through an abandoned well. It is then picked up by conveyor belts and brought to the face. Here it is transferred to shaker conveyors hanging on chains that pile up the back-fill into place. The walling material (props, bars, lagging-poles) is also dumped in through the same hole as the back-fill. (Fig. 34.) This method (which had been suggested by a former miner) is a peculiar characteristic of the oil shaft of Wietze. The dumping of the walling material down to a depth of 495 ft. (150 m) is accomplished without any damage whatever.

For the centrally controlled ventilation of the network of tunnels there are about 15 wells in addition to both shafts for letting the air in and out. At a volume of air of 106 cu. ft. (3 cbm) per man and minute, our air analyses exhibit the following picture:

20 to 20.5 per cent of oxygen.
79 to 79.5 per cent of nitrogen.
0.1 to 0.2 per cent of methane.

No special measures are required for the draining of the mine.

Up to the end of 1952 about 36,778,011 cu. ft. (1,041,870 cbm) of oil sand had been recovered including 25,769,000 cu. ft. (730,000 cbm) in the actual mining of the oil sand by excavation, the rest in the driving of seepage tunnels.

(c) Processing of the Oil Sand on the Surface

The oil sand recovered from the mine is treated in the washing plant immediately adjoining the territory of the shaft.

The washing process is as follows: (Fig. 35.)

The sand is screened, crushed and heated for 75 minutes in three boilers by hot-steam and compressed-air agitation. The separated oil is then run through a mud separator M to the electric Cottrell settling plant where the residual water is separated. The residue of the mud separators flows into the secondary settling plant O consisting of large containers in which the mud-water-contents are agitated by compressed air. (Fig. 36.)

Fig. 37 illustrates the ground-plan of the Wietze mine with its three different working methods:

A = Excavation of oil sand.
B = (1) Seepage tunnels with flat bedding.
    (2) Seepage tunnels with steep bedding.
C = Light-oil recovery by holes drilled from a subsurface tunnel on the strike.

(d) Subsurface Flushing Method

The description of the excavation of the oil sand has shown that the expenses are very considerably increased by the subsurface excavation of the oil sand, its hoisting to the surface as well as its washing on the surface and its return to the mine as back-fill. A new rational processing method is a subsurface flushing process conducted according to the procedure illustrated in Figs. 38 and 39. The sand loosened by pneumatic picks is flushed with water at a temperature of 68° F. (20° C.). This intense agitation or flushing separates the oil from the sand grains. Even at the highly viscous tar-oil of Athabasca, this cold-water treatment has proved successful.[*] Though the present results of 70 to 80 per cent cannot yet be regarded as fully satisfactory and are probably caused by the varying clay content, the application of surface-active chemicals, which is being tested here at present, might lead to a more promising development.

(2) Heide

(a) General

Another oil mine was operated at Heide in Holstein in the north of Germany.

As already mentioned, the chalk of the Senonian at depths of 164 ft. (50m) and 459 ft. (140 m) is irregularly impregnated with heavy oil in a part of the Heide field. Owing to the strong bond between the chalk and the oil it has as yet been possible to recover only very small amounts of oil from wells, so that it was decided, on the basis of the proven reserves, to start mining the reservoir rock. In 1919, the first shaft was sunk down to 328 ft. (100 m) by Deutsche Petroleum A. G., the predecessor of Deutsche Erdoel-A. G. At 180 ft. (55 m) or 262 ft. (80 m) respectively two levels were started. In 1926, however, the operations had to be stopped, as it had not yet been possible to provide the technical basis of an economic recovery and treatment. Between 1926 and 1929 the reservoir rock and overburden were explored by means of 78 wells with a total depth of 19,680 ft. (6,000 m). After having estimated the reserves at 30 million metric tons of oil chalk. Shaft I was deepened to 522 ft. (159 m) in 1941, and a new level was started at 459 ft. (140 m) in order to approach the reservoir from the underlying beds. This shaft was developed as a hoisting shaft; a little later Shaft I was sunk to 295 ft. (90 m) to serve as ventilation shaft.

(b) Methods of Subsurface Mining

It is impossible to compare the mining at Heide either to Wietze or even less to Pechelbrunn, since the chalk, exhibiting very characteristic structural features, contains the most viscous oil of all three deposits that cannot be made to flow by any normal methods. A recovery by seepage, therefore, becomes impossible with any normal means, unless high temperatures are applied in place according to similar laboratory tests conducted in the United States and in Europe, or unless the chalk is made to dissolve by chemical methods, as e.g. by acidizing. These methods, however, are yet in their preliminary stages and cannot be applied at Heide owing to the insufficient thickness of the loose Diluvial overburden. Thus the oil chalk can be recovered only by direct excavation below the surface in open-pit mining, which has been tried. (Fig. 40.)

The thickness of the oil-chalk reservoir of 164 (50 m) to 230 ft. (70 m) required the application of bankwork as shortwall workings with solid back-fill. Starting in the underlying beds, the first bank with a face length of 98 ft. (30 m) to 164 ft. (50 m) and a height of 8 ft. (2.5 m) was hewn out in bank-work proceedings from the limits. The supports at the face were made of wood, the same as at Wietze. The oil chalk was recovered by pneumatic picks, which did not cause any extraordinary difficulties at first. The removal of the recovered oil chalk on belts or in haulage mine cars was surprisingly easy, though certain difficulties occurred in the driving operations, as gases of a more or less high intensity were frequently encountered and occasional blowouts occurred, which both exercised a rather disagreeable effect. The development of mine gases is rather strong in the oil chalk; it could be prevented, however, by the application of an effective ventilation system; on the other hand the development of gases had the advantage of

Figure 29—Removal of oil sand from wall face. Mine of Wietze.

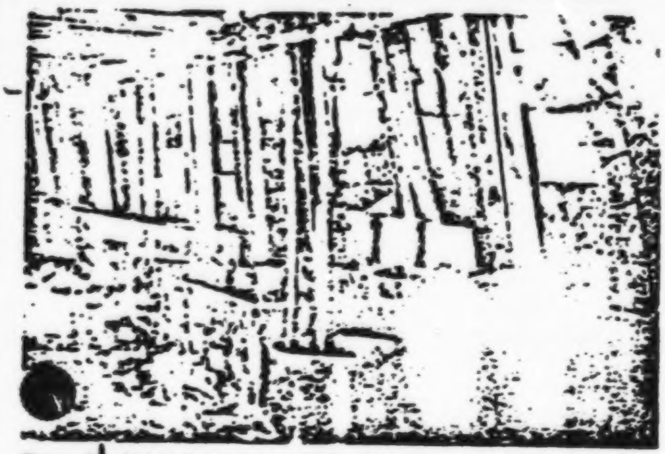


Figure 23—Finished seepage tunnel with gutters and shaft as well as mounted automatic pressure apparatus.

Figure 28—Recovery of oil sand at wall face. Mine of Wietze.

furthering the recovery of the oil chalk by making the latter scale off while the gas hissed out.

Again similar as at Wietze, before driving the tunnels the walling had to be examined as to its stability and life. The first tunnels had been walled and had seemed satisfactory at first. When enlarging the network of tunnels and starting exploitation, pressure waves were generated that made part of the walled tunnels collapse. Owing to this experience, tests were made with various iron wallings, all of which did not prove satisfactory, however. Only the cone-shaped brick walling (System Hersbruch) withstood the rock pressure.

The various types of walling tested in the mine of Heide are to be seen in Figs. 41 to 44.

(c) Processing of the Oil Chalk on the Surface

Much more troublesome than the recovery of the oil chalk in the mine proved its treatment, i. e., the separation of the oil from the chalk. Laboratory investigations having lasted for years clearly indicated that mechanical wet washing or solution of the oil in the chalk did not yield economic results, so that the only promising possibility was a temperature treatment—the low-temperature carbonization of the oil chalk.

The low-temperature carbonization tests conducted in the laboratory were so satisfactory that it was decided to erect two small pilot low-temperature carbonization plants, in order to test the technical and economic feasibility of this procedure in tests of long duration. The tunnel-type Lurgi furnace and the disc-type Buettner furnace proved satisfactory during that test, so that, on the basis of these experiences, the final low-temperature carbonization plant could be erected without taking any major risks. In 1942 the erection of a large-scale low-temperature carbonization plant with a daily capacity of 1,000 metric tons was started. The flow sheet is as follows (Fig. 45):

The haulage mine cars filled with coarse oil-chalk are run through a tunnel-furnace with a length of 197 ft. (60 m) in which the temperature is increased to 842° F. (450° C.). Fine grained oil chalk is low-temperature-carbonized in the disc-type Buettner furnace. The driven-out gases are precipitated in three fractions in the condenser at temperature stages of 392° F. (200° C.) and 554° F. (290° C.).

The carbonized chalk substance which contained only a few per cent of oil by weight was mixed with sand and returned to the mine as back-fill or processed for the manufacture of building or fertilizing lime.

In Fig. 46 we see the ground-plan of the Heide mine with its tunnel network of 42,640 ft. (13,000 m) up to 1945, the location of the workings, the back-fill and ventilation holes and the places where gas eruptions had been observed.

The surface plants, that had been erected at high investment costs, were completely destroyed by eight air raids, so that the mine had to be drowned for a second time after the war.

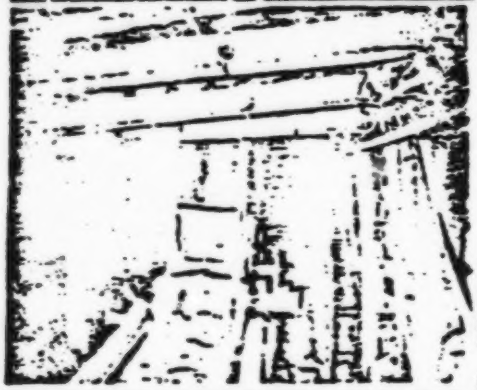
Concluding we should once more emphasize that Heide cannot be compared to any normal oil mines. The utilization of this oil-chalk deposit is much more closely related to the recovery of oil-shale, though it involves additional problems not encountered in oil-shale mining.

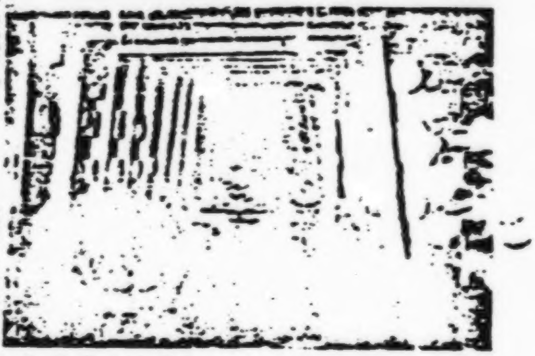
(C) Economic Section

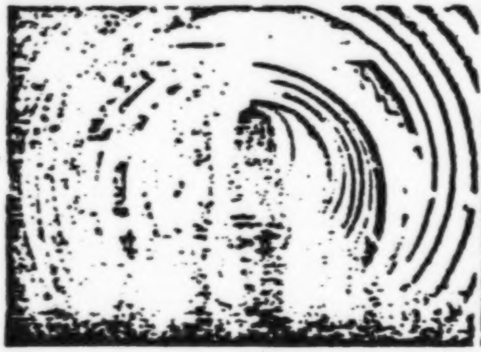
I Special Considerations Concerning Wietze

It is not quite easy to bring data showing the economic aspects of oil mining, as the conditions are different in different reservoirs and countries. There is no sense in citing absolute prices or costs which cannot be compared to other countries or methods. So we will only regard a number of characteristic drainage and efficiency factors of the Wietze mine, of which the following seem to be important:

(1) Efficiency of seepage methods as compared to the drainage by means of wells,







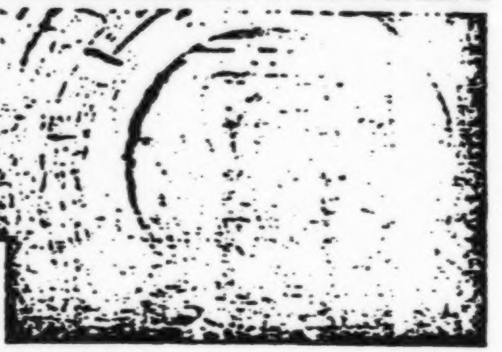


Figure 31—Top Upper Left. Setting of auxiliary workings at wall-face. (Spiling) Mine of Wietze.
Figure 34—Top Center. Hole for dumping-in the back-fill and walling material. Mine of Wietze.
Figure 32—Top Upper Right. Hoisting of oil sand by conveyor-belt at wall-face. Mine of Wietze.
Figure 33—Center Left Column of Pictures. Removal of back-fill below the surface. Mine of Wietze.
Figure 43—Bottom Left Column of Pictures. Circular iron walling and oval iron walling in the Mine of Heide.
Figure 36—Bottom Center. Agitation of waste-waters from the processing and settling plants of the Wietze Mine.
Figure 41—Center Right Column. Walling of trapezoidal iron frames and wooden pilings in the Mine of Heide.
Figure 44—Bottom Right Column. Cone-shaped brick walling. (System Horstbruch.)

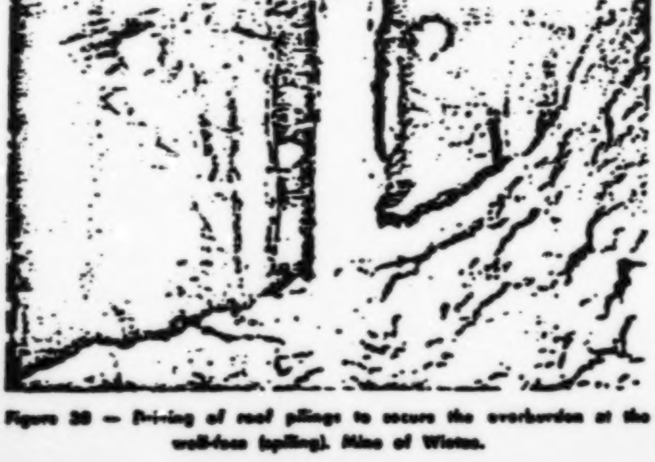


Figure 38 — Driving of roof pilings to secure the overburden at the wall-face (spiling). Mine of Wietze.

Figure 40—Left. View of oil-chalk mining in the Mine of Heide.
Figure 42—Right. Oval iron-walling in the Mine of Heide.

(2) Ultimate recovery per 1 foot of tunnel length,
(3) Spacing and location of seepage tunnels,
(4) Material costs per 1 foot of tunnel [illegible]ngth and working efficiency per [illegible]it of time,
[illegible] investments.

Efficiency of the Seepage Method As Compared to the Drainage by Means of Wells

It has already been mentioned that in he case of the heavy oil of Wietze 15 o 18 per cent may be recovered primarily by means of wells and 22 to 26 er cent secondarily by seepage into unnels. It is, therefore, obvious from he standpoint of the exploitation engineer or the geologist, that the seepage nethod, owing to its enlarged oil-yielding surface, will make possible the recovery of additional oil after the primary hase of production has come to a close. t should be added, however, that the bove comparison can by no means be onsidered as accurate, as our calculaions had to be based on the status of 920.

If oil mining had not taken its start n that year, the primary recovery by ells would have increased. In that case art of the oil that has been recovered rom the seepage tunnels would have een produced by wells. The peak of the ecovery by wells was already reached t Wietze in the years between 1900 and 910 [illegible]ter all, so it may be assumed that h[illegible]ary recovery would not have u[illegible]d 20 per cent. In contrast to his, it may also be surmised that seepge oil recovery alone without any wells ould have yielded 37 to 44 per cent etween 1874 and 1920. Thus the seepage il method as used at Wietze may be onsidered an extraordinarily efficient ethod of secondary recovery that will lmost double the primary ultimate outut and may also be applied as a rimary method of production. In the atter case it would be much more proftable, since the drilling expenses for bout 480 wells with about 412,500 ft. ould have been saved.

Ultimate Recovery Per 1 Foot of Tunnel

The total output of the seepage tunels per 1 foot of tunnel from the beinning to the end of the mining period an important criterion when regardng the seepage-oil recovery from the conomic aspect. It is, of course, dependnt upon the thickness of the reservoir nd the spacing of the tunnels.

In our case 1 foot of tunnel length in he oil sand corresponds to an oil sand rainage volume of 2,647 cu. ft. (246 bm per 1 m) (refer below), the recovery act[illegible]ing 18.6 bbl. per ft. (9.2 tons/m). Jp [illegible] end of the life of the reservoir [illegible] probably increase to 24.5 bbl. per t. (12.1 tons/m). In other words: the ssets of the economic balance are the roceeds from these 24.5 bbl. (12.1 tons) r about 21.3 bbl. if the tunnels in the layey rocks are also considered (10.6 ons) that must also be paid for by the proceeds. The liabilities are the expenses for the maintenance of the tunnels, the material, wages, overheads, etc. during the whole duration of the seepage recovery. By comparing both items one may form a rather satisfactory idea of the economy of this method, which is quite independent of the country and its living cost index, though it is in any case dependent upon the reservoir conditions of the respective deposit.

(3) Spacing and Location of Tunnels

Another interesting and important item is the spacing and location of the tunnels. This item corresponds to the well spacing problem in normal oil fields. On the one hand, it is desired to increase the well spacing in order to save expenses, on the other, we are aiming at the recovery of all of the oil. In our case it is also desired or even imperative to do the work with as few tunnels as possible, on the other hand, however, our object is to obtain a maximum seepage output. The conception of the spacing of the tunnels rather refers to volume than to the surface area and is defined as the unit volume of oil sand that corresponds to 1 foot of the seepage tunnel, which amounts to 2,647 cu. ft. (246 cbm per 1 m) of oil sand (total reserves 563,200,000 cu. ft. (16,000,000 cbm) of oil sand: 213,200 ft. (65,000 m) of tunnels up to the end).

If one cubic foot of oil sand yields 0.013 bbl. of oil in the seepage phase (compare Table 4), there should result an outflow of 33 bbl. (16.4 tons per m) of oil per foot. The maximum recovery, however, reaches but 24.5 bbl. per ft. (12.2 tons per m). The difference of 8.5 bbl. (4.2 tons) may only be explained by the fact that about 25 per cent of the oil sand, i.e., the whole oil sand below the deepest story of the tunnels up to the edge-water contact or up to the underlying beds, is not being depleted, as the oil cannot flow upwards when drained by gravity.

On the other hand, it is concluded that the seepage tunnels should run as deeply as possible, directly above the underlying beds or above the edge-water contact, and that a closely spaced network of tunnels should be driven there. Several stories of tunnels one above the other should be driven only in case of a geological necessity, as they would otherwise only impair the economic profit.

(4) Material Costs Per 1 Meter of Tunnel Length and Working Efficiency Per Unit of Time

A detailed economic analysis would far surpass the limits of this report, since new reservoir, engineering and financial conditions have to be considered for every mining project. So we shall have to restrict ourselves to a few characteristic figures similar to those that have already been given in the paragraph on drainage. The following figures refer to Wietze.

The driving of 1 meter (3.28 ft.) of tunnel costs at present DM 300.- to 350.-. These include about 55 per cent for the walling material, e. g. wood for the lagging and sleepers, iron for frames, caps, rails, pipe lines, etc., furthermore, about 15 per cent piece wages including social charges for the driving of the tunnels, 15 per cent for hoisting from the face to the surface, the remaining 15 per cent for overheads.

In other words: For 1 meter (3.28 ft.) of tunnel we require at Wietze:

39 ft. (12 m) of iron rails,
75 sq. ft. (7 m²) of wood,
3.28 ft. (1 m) of pipe line,
3.28 ft. (1 m) of air pipe,
timber sleepers.

The labor requirements for the present 10.8 miles (18 km) of tunnels are 25 bailers, 10 mechanics, and 6 men for current repair work.

It should not be neglected, however, that, technically, there are rather complicated mining conditions in the Wealden of Wietze. If the adjoining rock is consolidated as in the Dogger beds of Wietze, the material costs of the tunnel walling can be slightly reduced, since a great part of the timbering may be omitted and the iron may be replaced by the less expensive wood. Eventual additions to the driving costs by shooting operations will never reach the height of these savings.

The other feature is the working efficiency. Three men at a time normally work at the face and drive 4.9 to 6.6 ft. (1.50 to 2 m) of tunnel in an 8-hour shift. One hewer earns DM 16.- to 20.- per shift. Eventual savings might be achieved by a more intensive mechanization.

(5) Investments

All investments, maintenance and operating costs for the subsurface shaft as well as for the surface plants have been included in the above-mentioned figures as a respective depreciation. The amount of the investments and working capital required at the start of the mining operations is in each case dependent upon the respective local conditions.

II. General and Conclusions

Owing to the widely-branched science of petroleum that has been highly specialized in many countries, it is at present possible, by means of normal primary recovery methods to obtain an ultimate recovery that would have been quite out of the question 20 years ago.

Furthermore, the very extensive secondary methods of recovery have been very intensively developed especially in the United States. Recoveries of 50 to 70 per cent of the oil content cannot any more be regarded as rare exceptions in highly permeable light-oil reservoirs subject to a strong drive. If it is, furthermore, considered that, especially in recent years, so many promising starts have been made in developing new methods, the above-mentioned ultimate recovery figures are sure gradually to become safe factors the oil industry might depend upon.

The respective methods are the high-pressure gas injection, the Orco Process, water-flooding with surface-active chemicals, heating and low-temperature carbonization in situ, etc. Thus it may seem

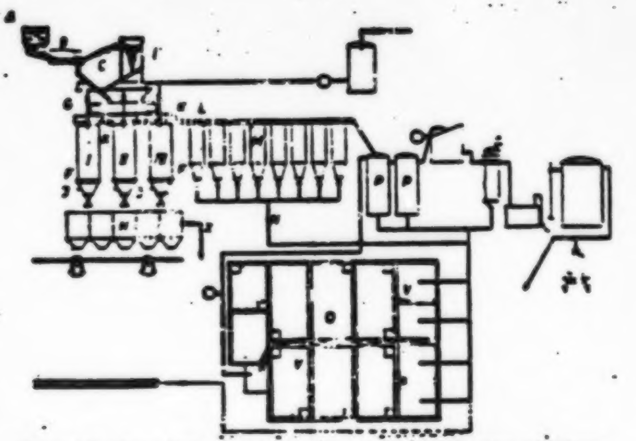
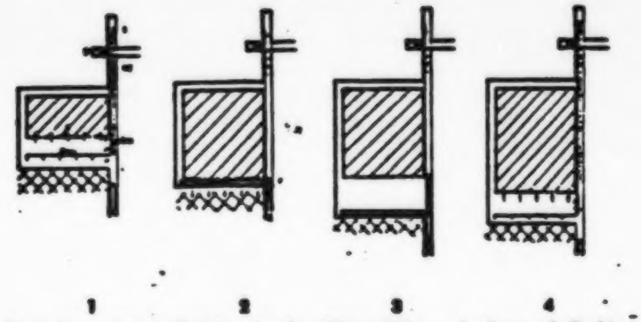


Figure 25—Flow sheet of oil sand processing at oil mine of Wietze.



Procedure of test flushing in the Wietze Mine: 1. Start of flushing procedure. 2. End of flushing procedure. Beginning of removal of excess sand. 3. End of removal of excess sand. 4. Start of flushing procedure.

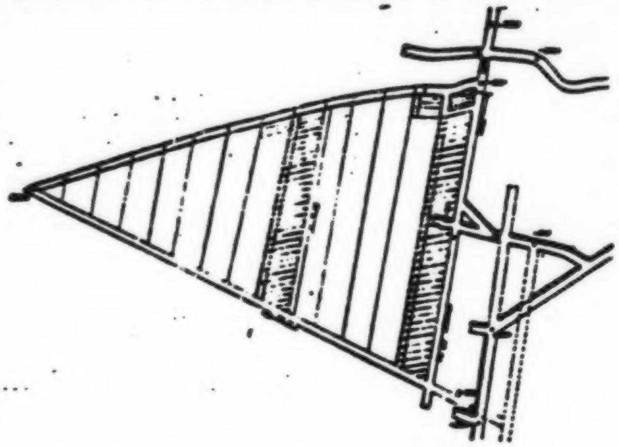


Figure 33—Diagram of test flushing in the Wietze Mine.

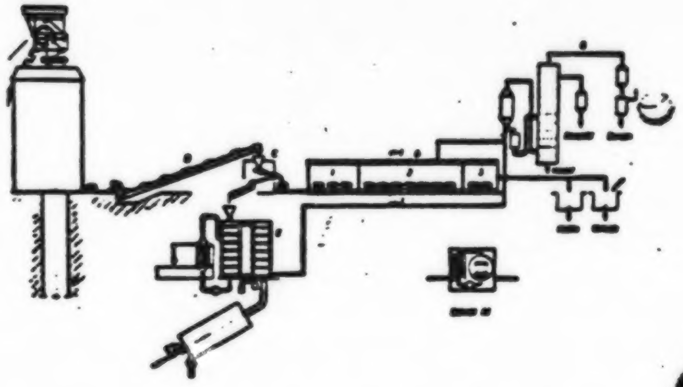


Figure 45—Processing of oil-chalk at oil mine of Heide.

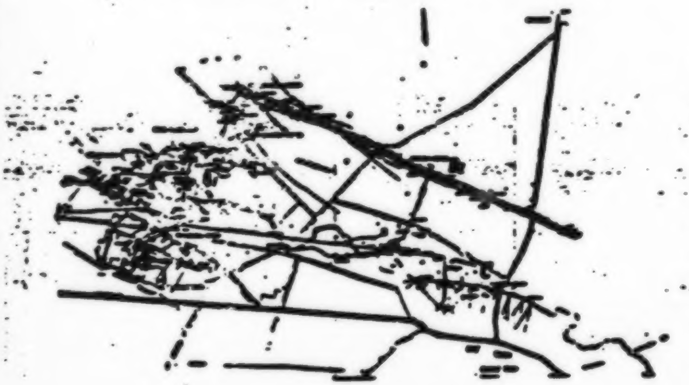


Figure 37—Ground plan of Wietze Mine.

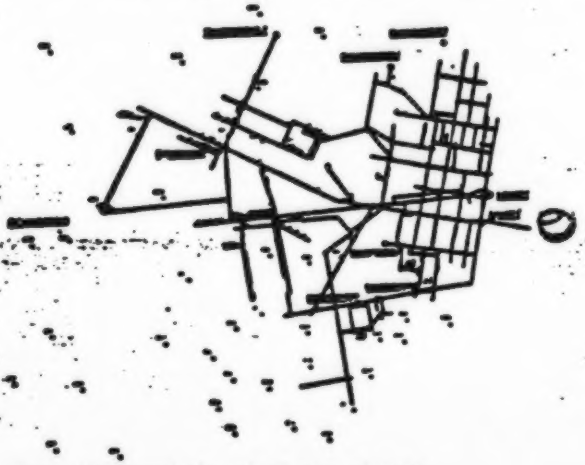


Figure 46—Ground plan of oil mine of Heide.

that no great possibilities are left over for oil mining.

A decisive reservation should be made here, however. With the exception of a few, our present secondary recovery methods can almost only be applied in light-oil reservoirs, even if they are more and more passed over into the range of primary recovery methods. The future will show how far the application range of the above-mentioned methods may later be enlarged to more viscous crudes. At present it is impossible economically to exploit a field having little pressure or no pressure at all by means [illegible] methods of recovery.

And at this point oil-mining will meet the problem of the stripper wells, which, looking back upon a productive life of decades, yield a very small output from fields devoid of energy, a group of wells that makes 90 per cent of all wells in the United States and, in part, requires state subsidies in order to avoid abandonment. Such wells exist in all countries of the world in which oil has been recovered for a certain length of time. This is the field where oil mining may set in, if the depth of the reservoir and all other required conditions are suitable.

And here the other question necessarily arises whether these old oil fields containing stripper wells and possessing reservoirs that had been poor in or devoid of any energy from the start, their ultimate recovery not surpassing 15 to 20 per cent, had really been operated and developed economically and yielded a financial profit? Would it not have been more advisable or is it not even now much more advisable to develop by mining such a reservoir that may be considered as suitable for mining from the start? For the oil of the primary production phase will in any case be recovered by mining and in addition to it there will be all the oil that flows into seepage tunnels owing to their en- ed oil-yielding surface. If Wietze e developed once-more today — the wells drilled would not be drilled in [illegible]ining would be applied as a [illegible] primary recovery. It is ex-[illegible] important to recognize the na- e of an oil reservoir in its early stage to decide in this very stage whether depletion by wells would not be bet- replaced by primary methods of min-

Those wells that will yet eventually e to be drilled until the reservoir ches a state of readiness for mining, e. g. wells for venting the gas, for tilation, or backfill, are of secondary portance only.

nother application of mining would in inaccessible territory. Many years , e.g., it had been planned to exploit reservoirs off the coast of Argentina t were suited for mining by a shaft l tunnels extending from the coast.

n addition to these more or less gen- l considerations, the method of min- will, of course, also play an impor- t part. The essential thing is the id substance in the reservoir rock, oil that is able to flow, and will flow o a system of wells or tunnels by its n gravity. This is one of or the actual k of oil-mining in the hundreds of old lds that yet contain billions of barrels residual oil. Whether their recovery ll be effected by indirect methods or ectly by seepage, is of secondary im- tance and depends upon local condi- [illegible] any case indirect mining has [illegible]ntage as compared to direct: en reservoirs that have not yet quite ached the state of readiness for min- g, may also be mined by means of itable engineering methods. As already ated, it is the great task of mining to cover as seepage-oil crude yet present old fields of crude that will probably main unrecoverable either by primary by secondary methods in new fields.

In most cases the excavation of the l sand will probably be connected with rtain difficulties of a financial nature the first place, as the excavation of e oil sand is, of course, much more pensive than the recovery by seepage. wing to reasons of national and social onomy, however, the excavation of the l sand at Wietze is being kept up. In rmal cases this method will not be resorted to in the first place, unless there are special reasons of a political or economical nature which will induce us to take up large-scale excavation of the oil sand even though the operating costs should surpass the crude oil price, which is the other great possibility of oil-mining. One thing is certain: The way to the last percentage of the oil in the reservoir solely leads through direct mining of the oil sand by excavation.

Already in 1928, Middendorf, then general manager of DEA, made the following far-seeing statement: "The mining method may, therefore, very considerably lengthen the life of an oil field. It is not the task of mining to replace drilling, the former should only be resorted to when all previous methods and means fail."

We might supplement this statement in the following way: Oil-mining can and should replace drilling as a primary method of recovery in shallow reservoirs suited for mining that cannot be exploited by normal primary or secondary methods of recovery. It is important to make the respective decision in an early stage, before enormous sums of money are invested in the drilling of wells.

Though oil-mining is being used in but a few localities of the world, it is by no means an old-fashioned method; on the contrary, in many cases it is the only applicable method and its profits, that are certainly obtainable, may yet be improved by combining it with modern methods of secondary recovery. We should keep in mind the possibilities of heat application which is to reduce the viscosity and consequently to improve the seepage capacity, a method already used in the recovery of coal. Let us, furthermore, mention the subsurface processing of the oil sand by means of a flushing method that, having been tested in the Wietze mine with good results, will yield a recovery of 70 to 80 per cent, while it becomes unnecessary to hoist the sand to the surface. Let us, furthermore, name the method of horizontal drilling from subsurface tunnels that was used at Wietze 20 years ago and has been applied at Pechelbronn with excellent results since 1951, which is considerably less expensive than deep drilling, while on the other hand, it enlarges the oil-yielding surface 10 to 20-fold. This method, being less expensive, is also able, combined with mining, to replace normal deep drilling from the very beginning of the exploitation. We will only hint at the fact that it is, of course, possible to combine this method with hot steam application or low-temperature carbonization in situ. Lastly we should like to point to the flooding tests at Wietze, which, combined with several other new methods, as e. g., the Orco process, might open new and interesting prospects.

Technically, the problems of oil-mining have been solved. In many cases it is the only possible rational method. Applied at the right moment and in the right shape, it may lead to the same financial profit as the recovery by wells. In reservoirs that come at all into question, the ultimate recovery will always be better than when the same reservoirs are exploited by means of wells.

Lastly, as already mentioned in the introduction, it should be kept in mind that—as no theoretical considerations or laboratory tests could—oil-mining is able to yield an opportunity of making tests and acquiring knowledge that will always be valuable to the petroleum industry.

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